UNITED STATES
NUCLEAR REGULATORY COMMISSION
TECHNICAL TRAINING CENTER

COMBUSTION ENGINEERING
TECHNOLOGY CROSS TRAINING COURSE
SYSTEMS MANUAL

This manual is a text and reference document for the Combustion Engineering Technology Cross Training Course. It should be used by students as a study guide during attendance at this course.

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Chapter 1

GENERAL PLANT DESCRIPTION

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1.0 GENERAL PLANT DESCRIPTION

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1.0 GENERAL PLANT DESCRIPTION

Learning Objectives:

1. Identify the major components included in the primary and secondary cycles.
2. Describe how reactor coolant temperature and secondary system pressure change with load.
3. State the function of engineered safety features.
4. Describe how heat from the primary cycle and primary cycle components is rejected to the environment.

Introduction

A typical pressurized water reactor (PWR) dual-plant cycle consists of two closed reactor coolant loops connected to the reactor vessel (primary), and a separate power conversion system for the generation of electricity (secondary).

The use of a dual cycle minimizes the quantity of fission products released to the main turbine, condenser, and other secondary plant components and subsequently to the environment. The following paragraphs describe the systems installed in a typical Combustion Engineering designed PWR. The information in this section was obtained from the Calvert Cliffs Final Safety Analysis Report (FSAR). Calvert Cliffs is the model plant for the Technical Training Center simulator and will be used for system descriptions in this manual.

1.1 Plant Site

The site for the Calvert Cliffs nuclear power plant consists of approximately 1,135 acres on the western shore of the Chesapeake Bay, in Calvert County, about 10.5 miles southeast of Prince Frederick, Maryland. The site is characterized by a minimum exclusion radius of 1,150 meters, remoteness from population centers, an abundant supply of cooling water, and favorable conditions of hydrology, geology, seismology and meteorology. The nearest population center is Washington, DC, which is approximately 45 miles to the northwest of the site.

1.2 Plant Layout

The turbine building at Calvert Cliffs is oriented parallel and adjacent to the shoreline of the Chesapeake Bay with the twin containment structures and auxiliary buildings located on the west, or landward, side of the turbine building. The service building and the intake and discharge structures are on the east, or bay side, of the turbine building (Figure 1-1).

Each containment structure houses a nuclear steam supply system (NSSS), consisting of a reactor, steam generators, reactor coolant pumps (RCPs), a pressurizer, and some of the reactor auxiliaries which do not normally require access during power operation. Each containment structure is served by a pendant-controlled, circular bridge crane.

The turbine building houses the turbine generators, condensers, feedwater heaters, condensate and feed pumps, turbine auxiliaries, and switchgear assemblies.

The auxiliary building houses the waste treatment facilities, engineered safety feature (ESF) components, heating and ventilating system components, and the emergency diesel generators (EDGs).

1.3 Reactor

The reactor (Figure 1-2) is a pressurized light water cooled and moderated type fueled by slightly enriched uranium dioxide. The uranium dioxide is in the form of pellets and is contained in zircaloy-4 (Zr-4) tubes fitted with welded end caps. These fuel rods are arranged into fuel assemblies each consisting of 176 fuel rods arranged on a 14 x 14 matrix. Space is left in the fuel rod array to allow for the installation of five guide tubes. These guide tubes provide for the smooth motion of control element assembly (CEA) fingers. The fuel assembly is fitted with end fittings and spacer grids to maintain fuel rod alignment and to provide structural support. The end fittings are also drilled with flow holes to provide for the flow of cooling water past the fuel rods.

The reactor is controlled by a combination of chemical shim and a solid absorber. The solid absorber is boron carbide in the form of pellets contained in Inconel tubes. Five (5) tubes of absorber form a CEA (four tubes in a square matrix plus a central tube). The five (5) tubes are connected together at the tops by a yoke which is, in turn, connected to the control element drive mechanism (CEDM) extension shaft. Each CEA is aligned with, and is inserted into, a guide tube in the fuel assembly. Chemical shim control is provided by boric acid dissolved in the coolant (water). The concentration of boric acid is maintained and controlled as required by the chemical and volume control system (CVCS).

The reactor core rests on the core support assembly which is supported by the core support barrel. The core support barrel is a right circular cylinder supported from a machined ledge on the inside surface of the vessel flange forging. The core support assembly transmits the entire weight of the core to the core support barrel through a structure made of beams and vertical columns. Surrounding the core is a shroud which serves to limit the coolant which bypasses the core. An upper guide structure, consisting of an upper support structure, CEA shrouds, a fuel alignment plate and a spacer ring, serves to support and align the upper ends of the fuel assemblies, prevents lifting of the fuel assemblies in the event of a loss of coolant accident (LOCA), and maintains spacing of the CEAs.

1.4 Reactor Coolant System

The reactor coolant system (RCS) of each unit consists of two closed heat transfer loops (Figure 1-3) in parallel with the reactor vessel. Each loop contains one steam generator and two pumps to circulate coolant. An electrically heated pressurizer is connected to one loop hot leg. The coolant system is designed to operate at a power level of 2,700 MWt to produce steam at a pressure of 850 psia.

The reactor vessel, loop piping, pressurizer, and steam generator plenums are fabricated of low alloy steel, clad internally with stainless steel. The pressurizer surge line and RCPs are fabricated from stainless steel and the steam generator tubes are fabricated from inconel.

Overpressure protection is provided by power-operated relief valves and spring-loaded safety valves connected to the pressurizer. Safety and relief valve discharge is released under water in the quench tank where the steam discharge is condensed.

The two steam generators are vertical shell and U-tube steam generators each of which produces approximately 6 x 10^6 lbm/hr of steam. Steam is generated in the shell side of the steam generator and flows upward through moisture separators. Steam outlet moisture content is less than 0.20%.

The reactor coolant is circulated by four (4) electric motor-driven, single suction, centrifugal pumps. Each pump motor is equipped with a non-reverse mechanism to prevent reverse rotation of any pump that is not being used during operation with less than four (4) pumps energized.

1.5 Containment

The containment structure uses a pre-stressed concrete design. The structure is in the form of a vertical right cylinder with a dome and a flat base. The interior of the structure is lined with carbon steel plate for leak tightness. Inside the structure, the reactor and other NSSS components are shielded with concrete. An unlined steel ventilation stack is attached to the outside of the containment structure and extends to an elevation about 10 feet above the top of the containment dome. Access to portions of the containment structure during power operation is permissible.

The containment structure, in conjunction with engineered safety features, is designed to withstand the internal pressure and coincident temperature resulting from the energy released in the event of the LOCA associated with 2,700 MWt operation. The design conditions for the structure are an internal pressure of 50 psig, a coincident temperature of 276 °F, and a leak rate of 0.20% by weight of the containment air per day at design temperature and pressure.

1.6 Engineered Safety Features Systems

Separate ESF systems for each unit in conjunction with separate containment systems protect the public and plant personnel from accidental release of radioactive fission products, particularly in the unlikely event of a LOCA. These safety features function to localize, control, mitigate, and terminate such incidents to hold exposure levels below applicable guidelines.

The ESF systems are:

1. The safety injection systems, including high pressure safety injection (HPSI), low pressure safety injection (LPSI), and the safety injection tanks (SITs);
2. The containment cooling systems, consisting of the containment spray system, and the containment air recirculation and cooling system;
3. The containment penetration room ventilation system;
4. The containment iodine removal system and
5. The auxiliary feedwater system

For each unit, four (4) SITs are provided, each connected to one (1) of the four (4) reactor inlet lines. Each tank has a volume of 2,000 ft^3 containing 1,000 ft^3 of borated water at refueling concentration and 1,000 ft^3 of nitrogen at 200 psig. In the event of a LOCA, the borated water is forced into the RCS by the expansion of the nitrogen. The water from three (3) tanks adequately cools the entire core. In addition, borated water is injected into the same nozzles by two (2) LPSI and two (2) HPSI pumps taking suction from the refueling water tank (RWT). For maximum reliability, the design capacity from the combined operation of one HPSI and one LPSI pump provides adequate injection flow for any LOCA.

Should the design basis event (DBE) occur, at least one HPSI and one LPSI pump will receive power from the emergency power sources, since normal power is lost and one of the EDGs is assumed to fail. Upon depletion of the RWT, the source of water to the HPSI, LPSI, and containment spray pumps, is automatically transferred to the containment sump and the LPSI pumps are shutdown. One HPSI pump has sufficient capacity to cool the core adequately at the start of recirculation. During recirculation, heat in the recirculating water is removed in the shutdown cooling heat exchangers by the operation of the containment spray system. Further, the suction of the HPSI pumps may be manually aligned so as to inject sub-cooled water from the shutdown cooling heat exchangers directly into the RCS for core cooling

All LPSI and HPSI pumps are located outside the containment structure to permit access for periodic testing during normal operation. The pumps discharge into separate headers which lead to the containment. Figure 1-4 provides a simplified diagram of the safety injection systems.

The containment spray system supplies cool, borated water which reduces the temperature and pressure of the containment atmosphere. The pumps take suction initially from the RWT. Long term cooling is based on suction from the containment sump through the recirculation lines. In the recirculation mode of operation, heat is transferred from the recirculating borated water through the shutdown cooling heat exchangers to the component cooling system and ultimately to the Chesapeake Bay water via the component cooling heat exchanger.

The containment air recirculation and cooling system is also designed to provide capability for reducing the temperature and pressure of the containment atmosphere. The cooling coils and fans are sized to provide adequate containment cooling at DBE conditions without assistance from other containment heat removal systems. The heat is transferred to the service water system.

The containment penetration room ventilation system processes the leakage from the containment through the containment penetrations to reduce the radioactivity concentration. The penetration room is maintained at a negative pressure relative to the containment following a LOCA. The penetration room ventilation system is equipped with particulate and charcoal filters to remove radioactivity associated with particulates and iodines before discharging the leakage from the plant.

The containment iodine removal system recirculates containment air through charcoal filters to remove iodine from the containment atmosphere.

An auxiliary feedwater system is installed to provide feedwater to the steam generators in the event of a loss of feedwater or during accidents. The system consists of two (2) turbine-driven pumps and a motor-driven pump that receive water from the condensate storage tank.

The ESF systems are automatically started by the engineered safety features actuation system (ESFAS). The signals used to actuate engineered safety features are:

1. Pressurizer pressure,
2. Containment building pressure,
3. Containment radiation,
4. Steam generator pressure,
5. Steam generator level,
6. 4160 Vac ESF bus voltage and
7. Refueling water tank (RWT) level.

1.7 Reactor Plant Protection Control and Instrumentation Systems

1.7.1 Reactor Protection

Reactor parameters are maintained within acceptable limits by the inherent self-controlling characteristics of the reactor, by CEA positioning, by boron content of the reactor coolant and by operating procedures. The function of the reactor protective system (RPS) is to provide reactor operators with audible and visual alarms when any reactor parameter approaches the preset limits for safe operation. Should pre-selected limits be reached the RPS initiates reactor shutdown to prevent unsafe conditions for plant personnel, equipment and to the general public (Figure 1-5).

The RPS is divided into four (4) channels, each receiving trip signals from separate sensors when the relevant parameter reaches a preset level. If any two (2) of these four (4) channels receives coincident signals, the power supply to the magnetic jack CEDM is interrupted allowing the CEAs to drop into the core and shutdown the reactor. The RPS is completely independent of, and separate from, the reactor control systems.

The following is a list of the reactor trips:

1. Variable Overpower,
2. High startup rate,
3. Low reactor coolant flow,
4. Low steam generator water level,
5. Low steam generator pressure,
6. High pressurizer pressure,
7. Thermal margin low pressure,
8. Loss of load (turbine trip),
9. High containment pressure and
10. Local power density (Axial power distribution)

1.7.2 Reactor Control

The RCS provides for start-up and shutdown of the reactor and for adjustment of the reactor power in response to turbine load demand. The NSSS is capable of following a ramp change from 15 to 100% power at a rate of 5% per minute and at greater rates over smaller load change increments up to a step change of 10%.

The control may be accomplished by automatic CEA movement in response to a change in reactor coolant temperature, or with manual control capable of overriding the automatic signal at any time. The temperature control program (Figure 1-6) provides a demand temperature which is a function of power. This temperature is compared with the coolant average temperature; if the temperatures are different, The CEAs are adjusted until the difference is within the prescribed control band. Regulation of the reactor coolant temperature in accordance with this program maintains the secondary steam pressure within operating limits and matches reactor power to load demand.

The reactor is controlled by a combination of CEAs and dissolved boric acid in the reactor coolant. Boric acid is used for reactivity changes associated with large but gradual changes in water temperature, xenon effects and fuel burnup. Additions of boric acid also provides an increased shutdown margin during the initial fuel loading and subsequent refuelings.

CEA movement provides changes in reactivity for shutdown or power changes. The CEAs are actuated by CEDMs mounted on the reactor vessel head. The CEDMs are designed to permit rapid insertion of the CEAs into the reactor core by gravity. CEA motion can be initiated manually or automatically.

The pressure in the RCS is controlled by regulating the temperature of the coolant in the pressurizer, where steam and water are held in thermal equilibrium. Steam is formed by the pressurizer heaters or condensed by the pressurizer spray to reduce pressure variations caused by volumetric changes of the reactor coolant due to RCS temperature changes.

1.7.3 Instrumentation

The nuclear instrumentation includes excore and incore neutron flux detectors. Ten channels of excore instrumentation monitor the neutron flux and provides reactor protection and control signals during start-up and power operation.

Four (4) Wide Range Logarithmic channels monitor the neutron flux from the source range to full power. Four (4) Power Range channels monitor the neutron flux range through the full power range. Two (2) additional Power Range Channels monitor the flux through the full power range for reactor control.

The incore monitors consist of self-powered rhodium neutron detectors and thermocouples to provide information on neutron flux distribution and temperature in the core.

The process instrumentation monitoring includes those critical channels which are used for protective action. Additional temperature, pressure, flow and liquid level monitoring is provided, as required, to keep the operating personnel informed of plant conditions, and to provide information from which plant processes can be evaluated and/or regulated. The boron concentration in the reactor coolant water is also monitored and is continuously recorded in the control room.

The plant gaseous and liquid effluents are monitored for radioactivity. Activity levels are displayed and off-normal values are annunciated. Area monitoring stations are provided to measure radioactivity at selected locations in the plant.

1.8 Electrical Systems

The Calvert Cliffs Nuclear Power Plant includes two generating units, the ratings of which are 1,020,000 kVA, 0.9 PF, 25kV, for unit I and 1,0 11 ,900 kVA, 0.9 PF, 22kV, for unit 2. Each generator delivers power to the 500kV switchyard through two 500,000 kVA main step-up power transformers. Two 500kV transmission lines connect to the switchyard and transmit the plant output to the network.

The plant distribution system utilizes voltage levels of 13.8 kV, 4.1 kV, 480Vac and 120/208 Vac. The system is designed to provide reliable power for normal operation and safe shutdown of the plant. Auxiliary and start-up power will be supplied by two service transformers capable of supplying the total auxiliary load of both units simultaneously. One service transformer is connected to each 500 kV bus in the switchyard

Four 125 Vdc systems provide continuous and emergency power for control, vital instrumentation, emergency lighting, vital 120 Vac loads, and computers. Both units share a 250 Vdc system which supplies power to the emergency lube oil and seal oil pumps. Separate battery systems are provided for substation control relaying, microwave telemetry, and communications.

The plant has four safety-related emergency diesel generators(EDGs), two dedicated to each unit. Any combination of two of the EDGs (one from each unit) is capable of supplying sufficient power for the operation of necessary ESF loads during accident conditions on one unit and shutdown loads of the alternate unit concurrent with a loss of offsite power.

1.9 Plant Auxiliary Systems

1.9.1 Chemical and Volume Control System

The purity level in the RCS is controlled by continuous purification of a bypass stream of reactor coolant. Water removed from the RCS is cooled in the regenerative heat exchanger. From there the coolant flows to the letdown heat exchanger and then through a filter and ion exchanger where corrosion and fission products are removed. It is then sprayed into the volume control tank (VCT) and returned to the RCS by the charging pumps through the regenerative heat exchanger.

The CVCS (Figure 1-7) automatically controls the rate of coolant removed from the RCS to maintain the pressurizer level within the prescribed control band thereby compensating for changes in volume due to coolant temperature changes. The VCT is sized to accommodate coolant inventory changes resulting from load changes from hot standby to full power. Using the VCT as a surge tank decreases the quantity of liquid and gaseous waste which otherwise would be generated.

Reactor coolant system makeup water is taken from the demineralized water storage system and from the two concentrated boric acid tanks. The boric acid solution in these tanks is maintained at a temperature which prevents crystallization. The makeup water is pumped through the regenerative heat exchanger into the reactor coolant loop by the charging pumps. Boron concentration in the RCS can be reduced by diverting the letdown flow away from the VCT to the reactor coolant waste processing system and using demineralized water for coolant makeup.

1.9.2 Shutdown Cooling System

The shutdown cooling system (SDC) is used to reduce the temperature of the reactor coolant at a controlled rate from 300°F to a refueling temperature of approximately 130°F and to maintain the proper reactor coolant temperature during refueling.

The SDC system utilizes the LPSI pumps to circulate the reactor coolant through two shutdown cooling heat exchangers, returning it to the RCS through the LPSI header. Component cooling water (CCW) is used to cool the shutdown cooling heat exchangers.

1.9.3 Component Cooling Water System

The CCW system consists of three (3) pumps, two (2) salt water cooled heat exchangers interconnecting piping, valving and controls. The corrosion-inhibited, demineralized water of this closed system is circulated through the component cooling heat exchanger where it is cooled to a temperature of 95 °F by the saltwater cooling system. Typical items cooled by component cooling water are:

1. Shutdown cooling heat exchanger,
2. Letdown heat exchanger,
3. RCP seals and lube oil cooler,
4. HPSI pump seals,
5. LPSI pump seals,
6. Waste gas compressors aftercooler and
7. Waste evaporators.

All items connected to this system and requiring cooling water are fed by parallel flow paths. A head tank floats on the system and absorbs the volumetric changes due to temperature changes.

During normal plant operation, only one (1) of the three (3) pumps and one (1) of the two (2) heat exchangers are required for cooling service.

During normal shutdown, two (2) of the three (3) pumps and both of the heat exchangers are utilized for cooling. For a LOCA, one (1) of the three (3) pumps and both of the heat exchangers can provide the necessary cooling.

1.9.4 Fuel Handling and Storage System

The fuel handling systems provide for the safe handling of fuel assemblies and the disassembly, and storage of the reactor vessel head and internals. These systems include a bridge crane and a refueling machine located inside containment above the refueling pool, the fuel transfer carriage, the tilting machines, the fuel transfer tube, a fuel handling machine in the spent fuel storage room, and various other devices used for handling the reactor vessel head and internals.

The spent fuel pool, located in the auxiliary building, consists of two identical halves. Each half serves one reactor unit. Both new fuel and spent fuel may be stored in the pool. Dry storage for new fuel is provided near the spent fuel pool. A fuel pool service platform is provided for manipulation of the spent fuel.

1.9.5 Cooling Water Systems

The exhaust steam of the main turbine and steam generator feed pump turbines is condensed by circulating water. Six (6) circulating water pumps per unit, having a combined volumetric capacity of 1,200,000 gpm, take suction from and discharge to the Chesapeake Bay through a three (3) shell condenser. The condenser pressure, under rated conditions, is two (2) inches of Hg (~ 1 psia).

A salt water cooling system shares the suction facilities with the circulating water system. Some important loads cooled by this system are the CCW system heat exchangers and the service water heat exchangers.

The service water system supplies a dependable continuous flow of cooling water to various plant components for the transfer of heat to the Chesapeake Bay.

Typical Components that are cooled by service water are:

1. Containment building coolers,
2. Spent fuel pool coolers,
3. Instrument air compressors and
4. Generator cooling.

1.10 Steam and Power Conversion System

The turbine generator for unit 1 is furnished by the General Electric Company. The turbine is an 1,800 rpm tandem compound, six (6) flow exhaust, indoor unit.

Under nominal steam conditions of 850 psig at the stop-valve inlet and with the turbines exhausting to a condenser pressure of 2 inches of Hg absolute, the unit 1 generator produces 883 MW. Turbine output corresponds to a NSSS thermal power level of approximately 2,700 MW.

The condensate and feedwater system (Figure 1-8) consists of three (3) condensate pumps, five (5) demineralizers, five (5) low pressure feedwater heaters, three (3) condensate booster pumps, two (2) high pressure feedwater heaters, and two (2) turbine-driven feed pumps.

Normally, the feed pump turbines are driven by reheat steam. At low turbine generator loads, main steam is used to drive the feed pump turbines. All turbines exhaust into their respective unit condenser.

1.11 Waste Processing systems

The waste processing systems provide controlled handling and disposal of liquid, gaseous and solid wastes. Gaseous and liquid waste discharges to the environment are controlled to comply with the limits set by 10 CFR 20.

1.11.1 Liquid Waste System

Reactor coolant from the CVCS and from the reactor coolant drain tanks is processed by the liquid waste system, which is comprised of filters, degasifiers, ion exchangers, evaporators, receiver tanks, and monitor tanks. The coolant is first purified by the filters, degasifiers, and ion exchangers.

The evaporators are used to reconcentrate the boric acid. The concentrate is normally returned to the boric acid storage tank, but if the activity is high, or if the solution is chemically unsuitable for reuse, the concentrate is processed in the solid waste processing system and transported to an offsite disposal facility. The distillate from the evaporators is monitored to ensure proper radioactivity limits are not exceeded and then discharged to the circulating water system.

1.11.2 Miscellaneous Waste Processing System

Miscellaneous liquid wastes from the auxiliary building are filtered and stored in the miscellaneous waste receiver tank. The miscellaneous waste ion exchanger is used to purify the miscellaneous waste before it enters the monitor tank. If the radioactivity level of the liquid in the monitor tank is found to be high, the waste can be recycled through the ion exchanger or sent to the liquid waste system.

The liquid in the monitor tank is sampled to ensure proper radioactivity limits are not exceeded prior to discharge to the circulating water system.

1.11.3 Waste Gas System

Waste gases are collected in the vent header and the waste surge tank. One (1) of the two (2) waste gas compressors is used to compress the gas for storage in one (1) of the three (3) waste gas decay tanks. After decay, the gas in the waste gas decay tanks is sampled to ensure proper radioactivity limits are not exceeded, and then is released to the plant vent at a controlled rate.

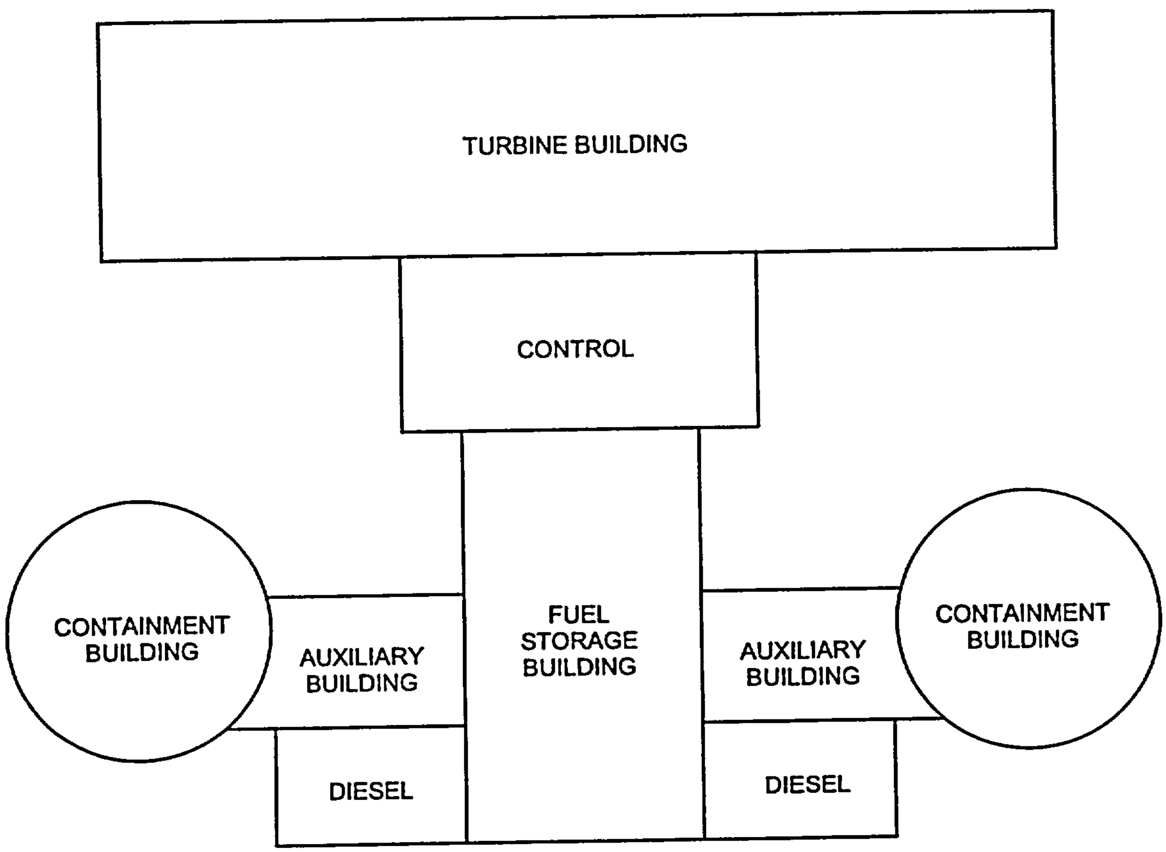

Figure 1-1 Plant Layout

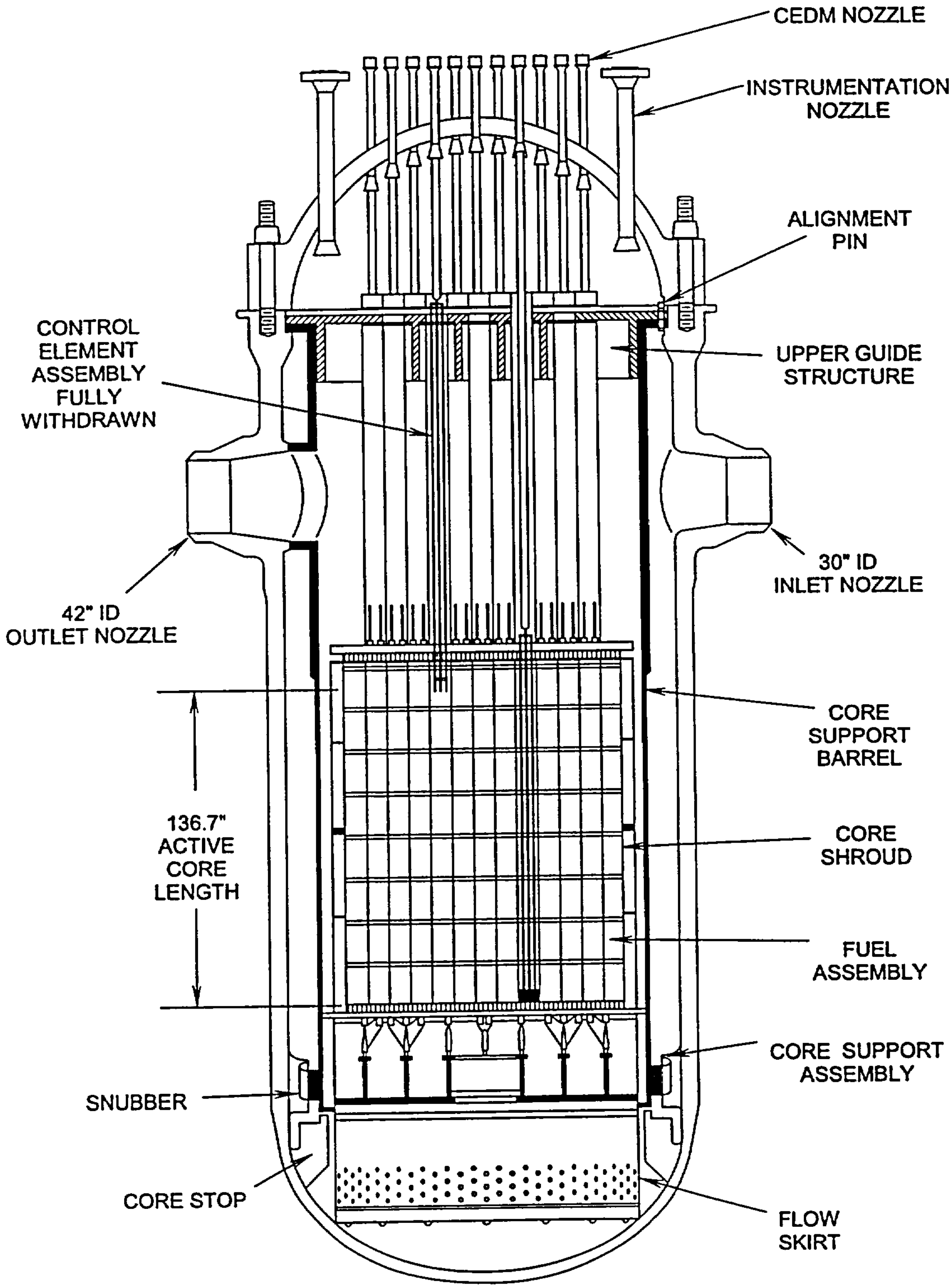

Figure 1-2 Reactor Vessel—Vertical Arrangement

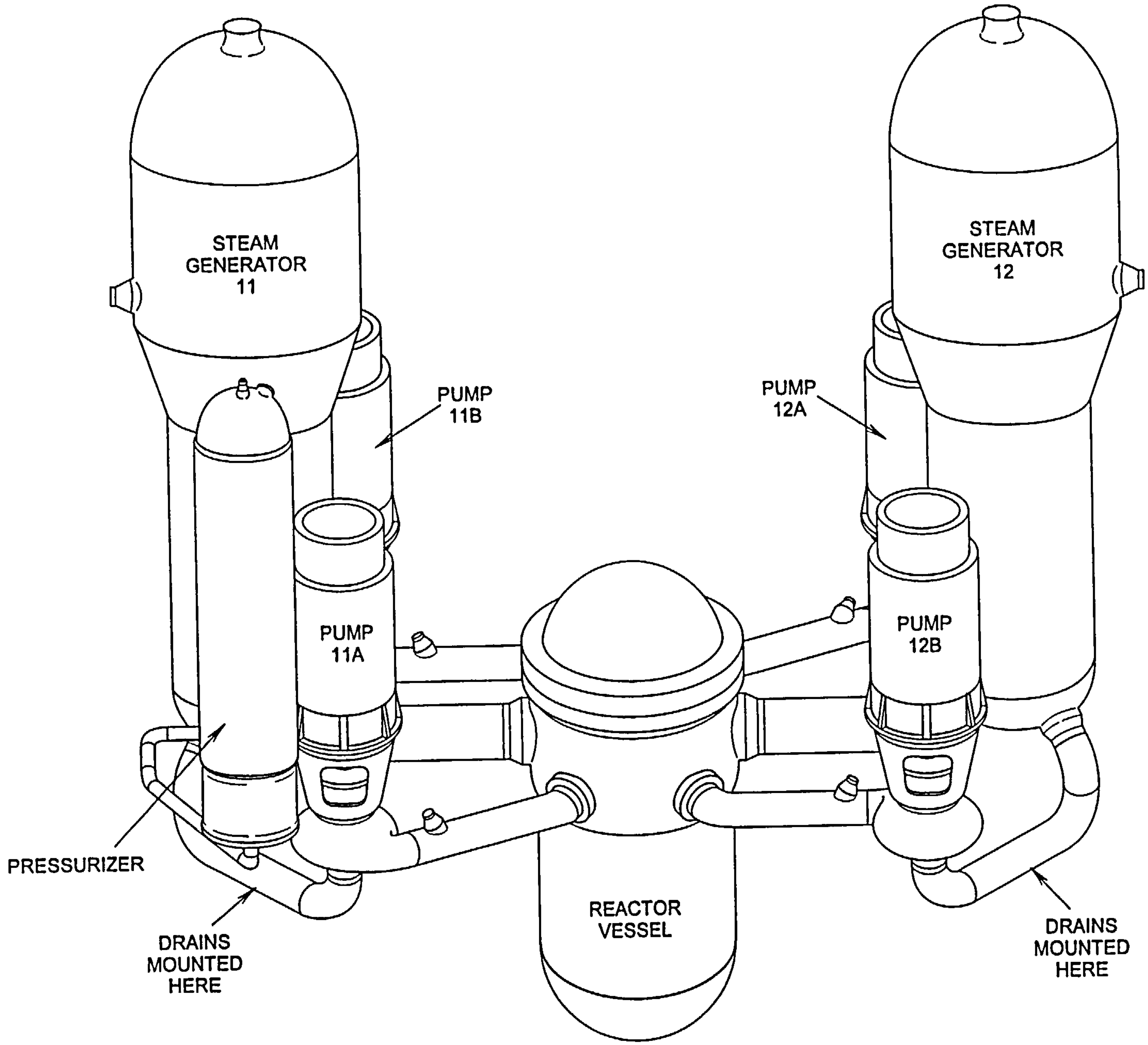

Figure 1-3 Reactor Coolant System

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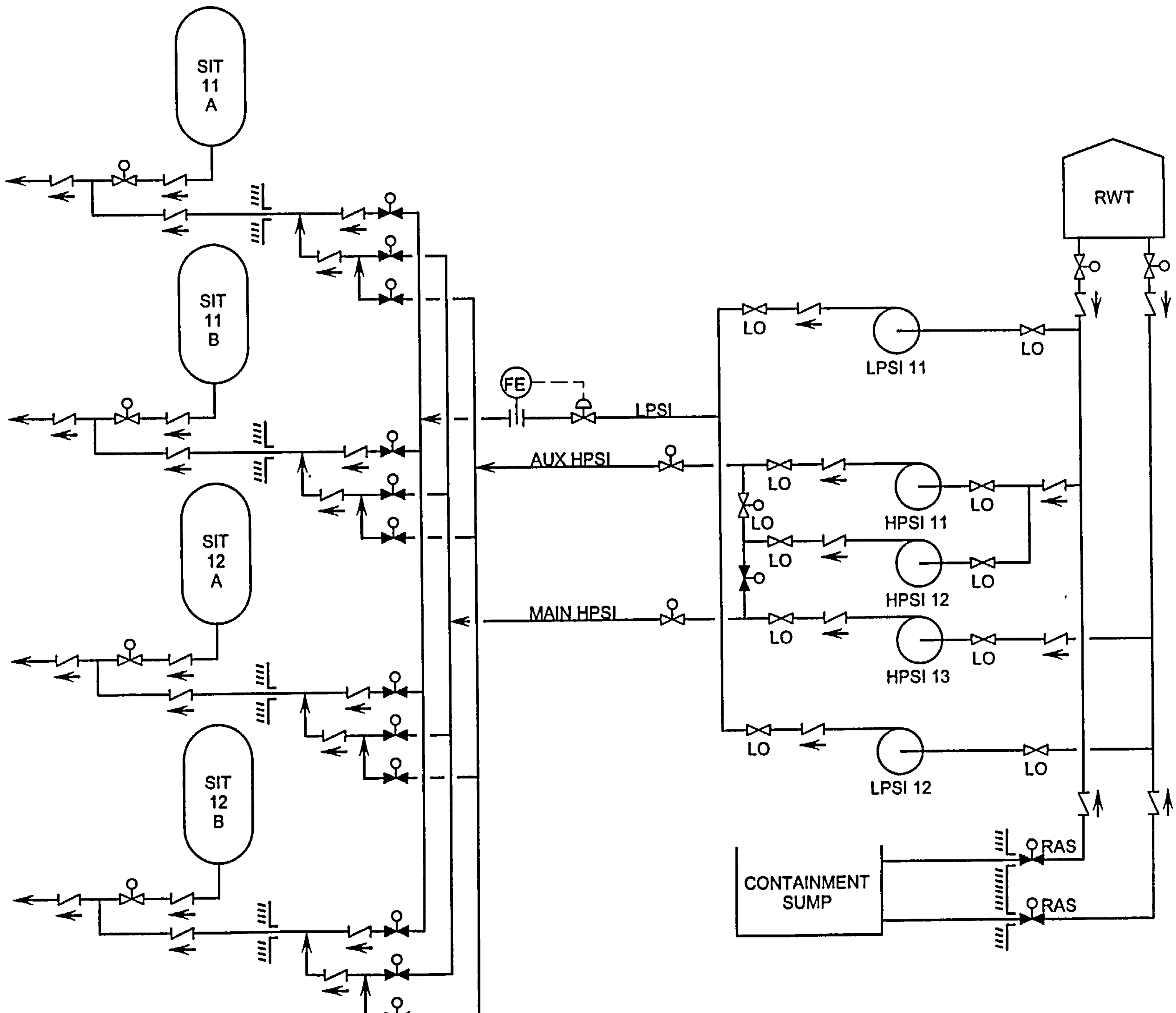

Figure 1-4 Emergency Core Cooling Systems

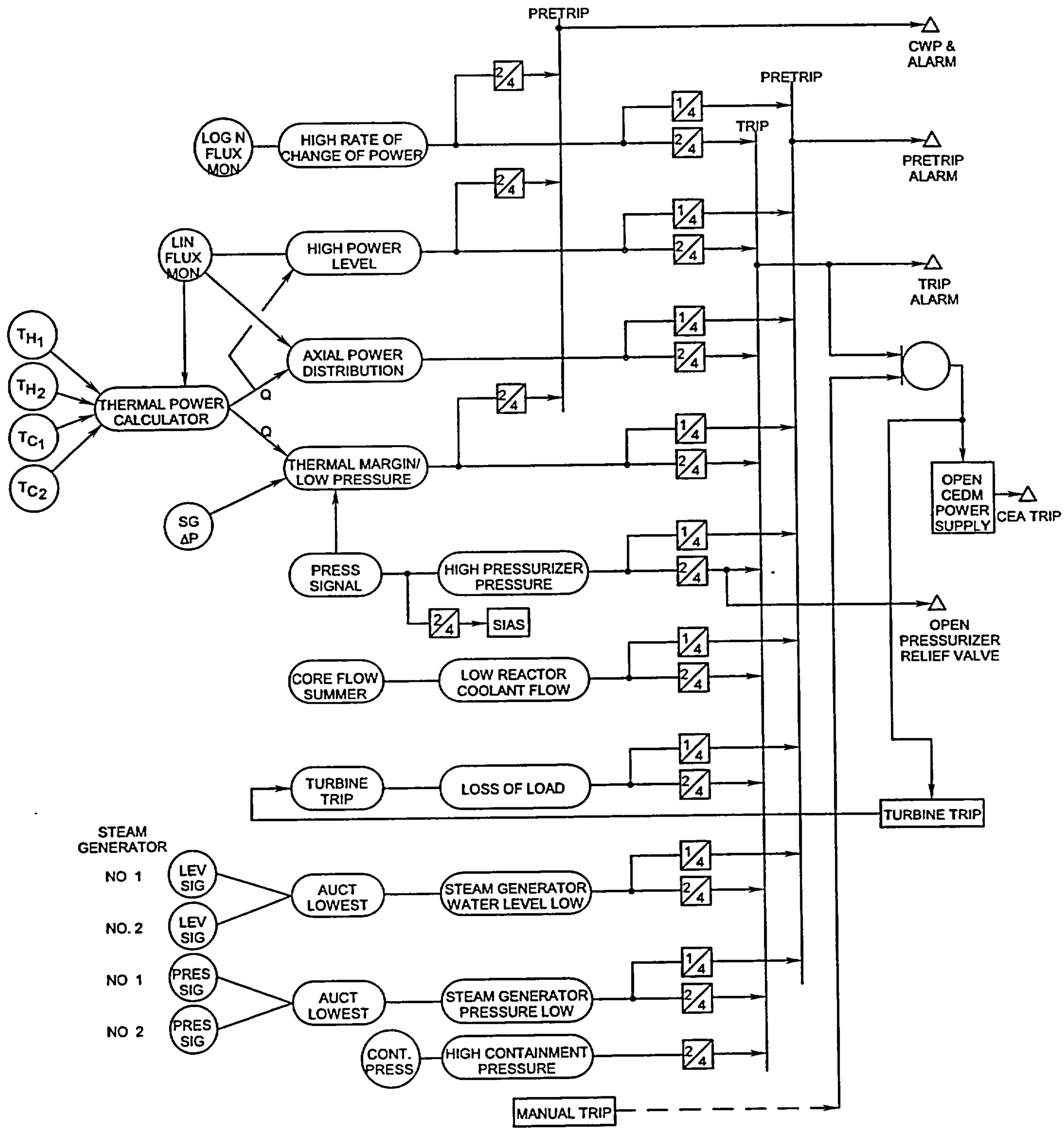

Figure 1-5 RPS Logic

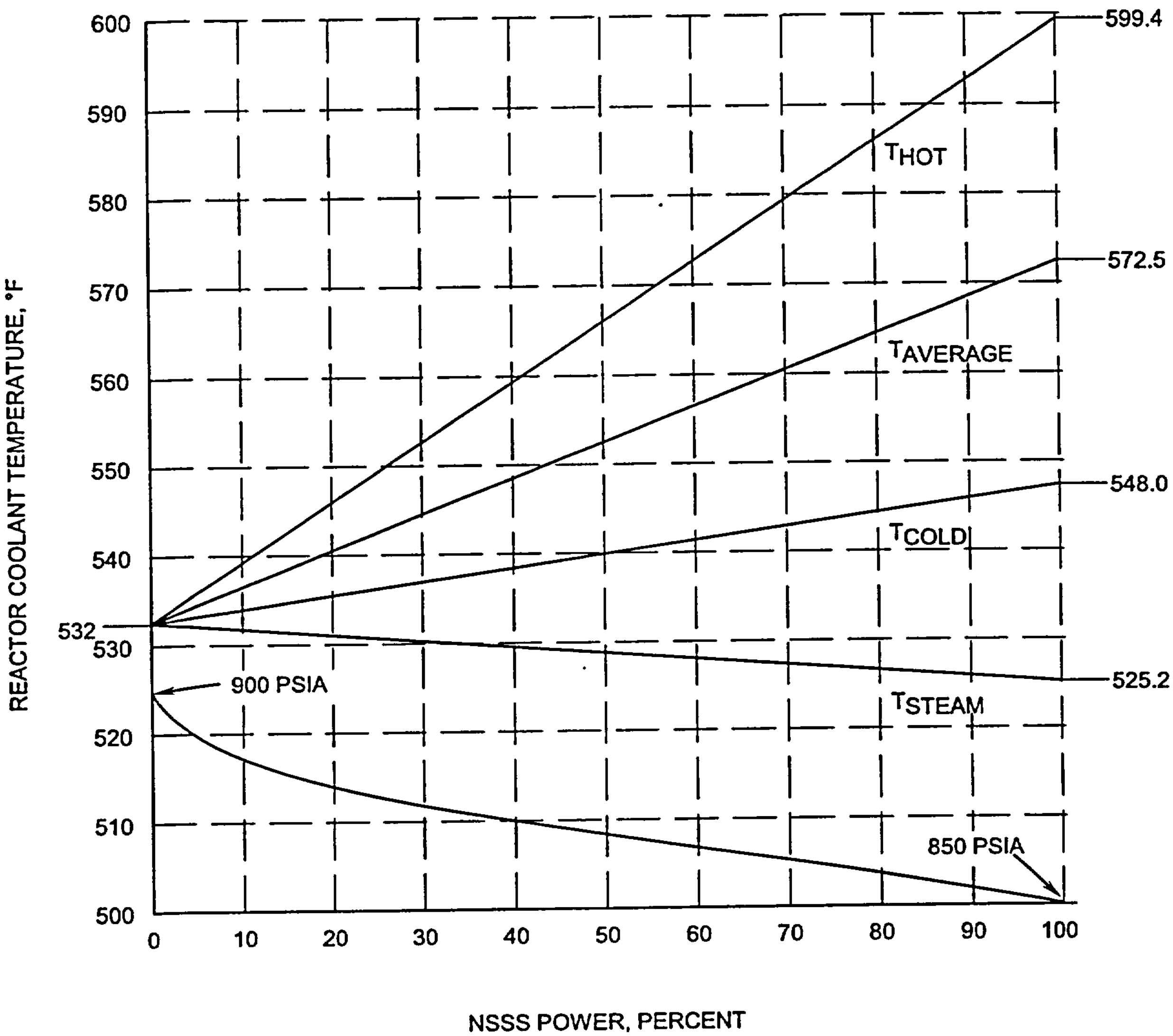

Figure 1-6 RCS Temperature Program

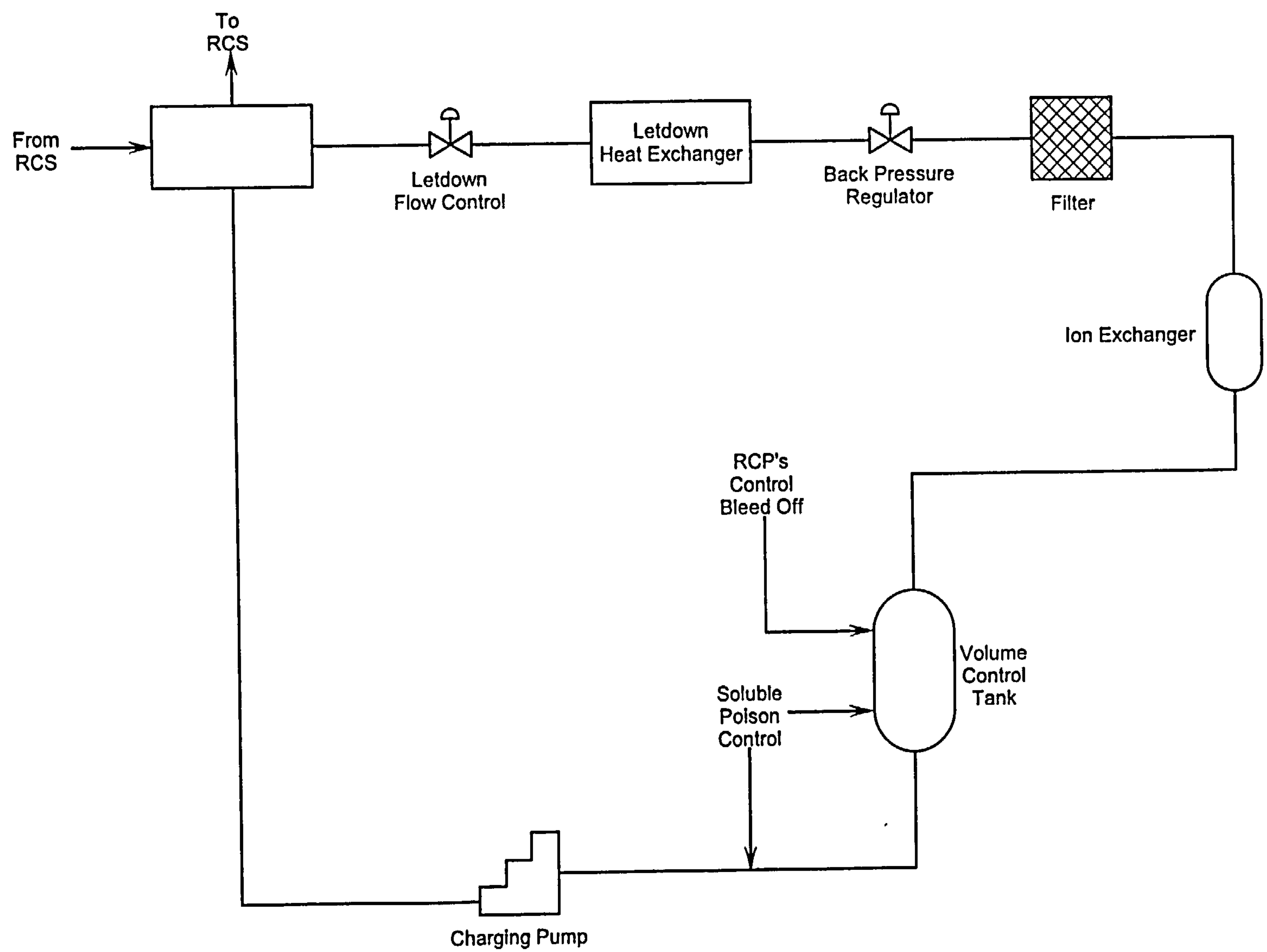

Figure 1-7 Simplified Chemical and Volume Control System

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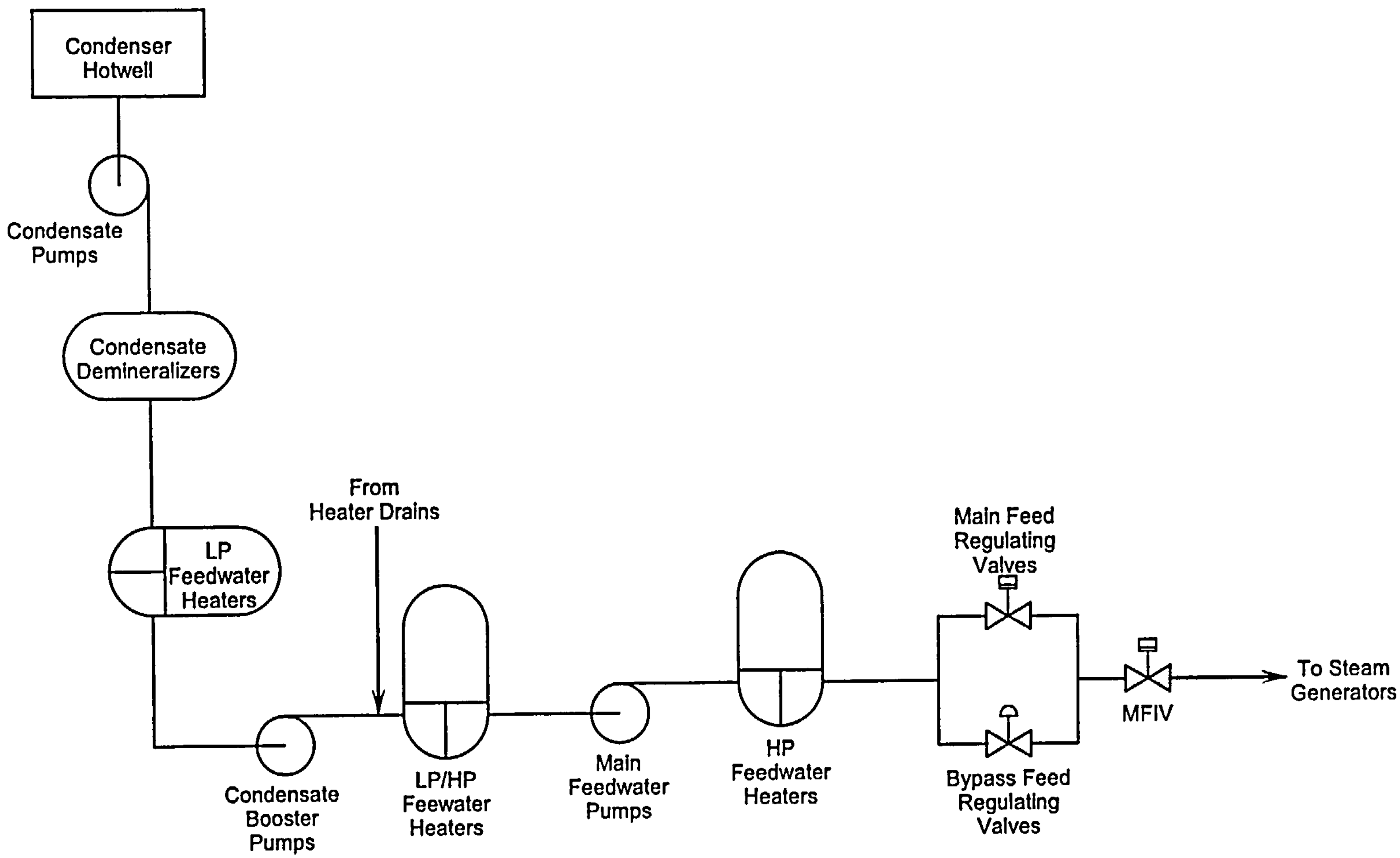

Figure 1-8 Simplified Condensate and Feedwater System

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Chapter 2

REACTOR COOLANT SYSTEM

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2.1 REACTOR COOLANT SYSTEM PIPING

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2.1 REACTOR COOLANT SYSTEM PIPING

Learning Objectives:

1. State the purpose of the reactor coolant system (RCS).

2. List and state the purpose of the following RCS penetrations:

   a. Hot leg (Th, reactor outlet piping)
      1. Pressurizer surge line
      2. Shutdown cooling system suction

   b. Cold leg (Tc reactor inlet piping).
      1. Chemical and volume control system (CVCS) letdown connection
      2. Pressurizer spray line
      3. Common penetration for high pressure safety injection (HPSI), safety injection tank (SIT), low pressure safety injection (LPSI) and shutdown cooling (SDC)
      4. CVCS charging connections

3. State the purpose of the following:

   a. Pressurizer
   b. Pressurizer safety valves
   c. Power operated relief valves (PORVs)
   d. Pressurizer spray valves
   e. Pressurizer heaters
   f. Quench tank
   g. Pressurizer auxiliary spray

4. Describe the methods for determining pressurizer relief valve leakage.

5. State the safety-related functions of the following RCS Instrumentation:
   a. Th resistance temperature detectors (RTDs)
   b. Tc RTDs
   c. Pressurizer pressure
   d. RCS flow

6. Explain the following:
   a. Pressurizer spray driving force
   b. Purpose of pressurizer spray bypass
   c. Low temperature/overpressure protection (LTOP)

2.1.1 RCS Purpose

The purposes of the RCS are:

1. Transfer the heat produced in the reactor to the steam generators.

2. Provide the second barrier to prevent the escape of fission products to the public.

2.1.2 General Description

The RCS may be divided into three (3) subsystems; heat source, heat sink, and the circulatory subsystem. The heat source is the reactor and the steam generators serve as the heat sink. This section will describe the circulatory subsystem.

Hot reactor coolant (Figure 2.1-1) exits the reactor vessel and travels to the steam generator through a 42 inch ID horizontal hot leg (reactor outlet). In the steam generator, the coolant transfers its heat energy to the secondary system and exits the generator via the two cold leg outlets. The coolant is directed by 30 inch ID piping to the suction of the reactor coolant pumps

(RCPs) which force the fluid back into the reactor vessel where the circulation path starts over.

The section of 30 inch ID piping from the steam generator outlet to the RCP suction is a short horizontal run with necessary bends required to mate with the steam generator and RCP suction. Coolant is directed from the RCP discharge through a short horizontal run of 30 inch ID piping to the reactor vessel. The cold leg consists of that portion of RCS piping from the steam generator outlet to the reactor vessel inlet. The piping is designed as compactly as possible to minimize the volume of coolant in the RCS. A small volume of coolant results in a lower containment building pressure in the event of a large break loss of coolant accident. Figure 2.1-2 shows a plan view of the standard Combustion Engineering two (2) loop, two (2) steam generator, four (4) pump RCS. Figure 2.1-3 illustrates a typical arrangement of RCS supports.

Since the RCS also functions as a barrier to the escape of fission products, it must be designed to very stringent requirements. The RCS piping is constructed of carbon steel, internally clad with stainless steel with a design pressure of 2500 psia and a design temperature of 650°F. The circulating reactor coolant is maintained in a subcooled condition by the pressurizer. Table 2.1-1 summarizes the design data for the RCS piping.

2.1.3 RCS Piping Penetrations (Figure 2.1-4)

2.1.3.1 Hot Leg Penetrations

The penetrations into the hot leg are the pressurizer surge line, shutdown cooling suction, RCS sample connection, and a loop drain to the reactor coolant drain tank (RCDT).

The 12 inch ID pressurizer surge line penetrates the 11 hot leg and is installed to allow the pressurizer to exert a pressure on the RCS, maintaining the RCS in a subcooled condition. In addition, the surge line allows the pressurizer to accommodate RCS volumetric changes caused by coolant temperature variations.

The 14 inch ID SDC suction penetrates the 12 hot leg and is used to remove decay heat during the latter portions of plant cooldowns and residual heat during cold shutdown operations. Shutdown cooling may be placed inservice at 260 psia and 300°F.

The RCS sample line penetrates the 11 hot leg and is a one-half inch ID line used for the routine sampling of the RCS. RCS chemistry is required to be maintained within specific limits in accordance with the plant's technical specifications.

The final penetration into the hot leg is the loop 11 connection to the RCDT which is used for draining down the RCS to its various maintenance levels. A connection for the RCS temporary level indication ties into the same penetration. The temporary level indicator is an unimpressive piece of plastic tubing that has a length greater than the highest point in the RCS. When the RCS is cooled down and depressurized, the level in the tubing equals the level in the system. The temporary level indicator is used to monitor RCS levels during maintenance.

2.1.3.2 Cold Leg Penetrations

The cold leg penetrations are used to

interface with the CVCS, the emergency core cooling systems (ECCS), the pressurizer, and loop drains. The CVCS interfaces consists of one (1) two (2) inch ID letdown line and two (2) two (2) inch ID charging penetrations. The letdown connection taps into the suction piping of 12A RCP and serves as the purification supply to the CVCS. The charging connections return purified coolant from the CVCS to the discharge of 11A and 12B RCPs.

The ECCS interfaces are 12 inch ID pipes that tie into the cold leg on the discharge side of each RCP. This connection serves as a common injection point for HPSI, the SITs, and LPSI. In addition, these connections provide a return path for cooled RCS fluid during SDC operations.

The two (2) three (3) inch ID pipes located on the discharge of 11A and 11B RCPs supply spray water to the pressurizer. If pressurizer pressure reaches a predetermined setpoint, the spray valves open allowing cold water to spray into the pressurizer steam bubble. This action lowers the saturation temperature and pressure of the pressurizer.

The last penetrations into the cold leg piping are the two (2) inch ID loop drains in the suction line to each RCP (this drain line shares a penetration with the letdown line in loop 12A). These drains are used to drain the RCS to various maintenance levels. The loop drains are routed to the RCDT which, in turn, is pumped to the liquid waste system.

2.1.4 RCS Instrumentation (Figure 2.1-5)

2.1.4.1 Loop Temperature Instrumentation

RCS loop temperature is sensed with precision, platinum resistance temperature detectors (RTDs). There are a total of 22 well-mounted RTDs, illustrating the CE philosophy of complete separation of control and safety systems.

Each loop hot leg has five (5) RTDs installed. In addition to the outputs for indication, alarm and the subcooled margin monitor (SCMM), four (4) of the RTDs supply wide range (0-700°F) safety grade signals to the reactor protection system (RPS) for the ΔT power reference calculation used in the thermal margin low pressure (TMLP) trip circuitry. The fifth RTD supplies a narrow range (515 - 615°F) control grade signal to the reactor regulating system (RRS) for calculation of average loop temperature (Tavg) and a high hot leg temperature alarm in the main control room (MCR).

Each loop cold leg has three (3) RTDs installed. Two (2) of the RTDs supply wide range (0-700°F) safety grade signals to the RPS for the ΔT power reference calculation used in the TMLP trip circuitry. The third RTD supplies a control grade signal through a selector switch to two temperature transmitters which supply the temperature signal to the RRS for calculation of Tavg, the control element drive system (CEDS) for an automatic withdrawal prohibit (AWP) feature and to the PORV control circuitry for LTOP protection. Upon loss of loop 11A (12A) input, loop 11B (12B) input can be manually selected to ensure a cold leg signal to the RRS.

2.1.4.2 Loop Flow Instrumentation

Reactor coolant flow is determined by measuring the reactor coolant pressure drop across the steam generators. The pressure drop across each steam generator is sensed by four (4) independent differential pressure detectors which are connected by piping from the hot leg to the cold leg connection of the steam generator.

The output signal from each flow detector is summed with the signal from the corresponding flow detector in the other loop. The result is four (4) independent channels of reactor coolant flow signal. Each channel provides a signal to individual flow indicators in the MCR and to the RPS for the loss of flow reactor trip.

2.1.5 Pressurizer

2.1.5.1 Pressurizer Design Information

As shown in Figure 2.1-6, the pressurizer is a cylindrical carbon steel vessel with rounded top and bottom heads and is clad with stainless steel on its internal surfaces. The pressurizer is supported by a cylindrical skirt welded to the bottom head. It is approximately 37 feet high, with a diameter of approximately nine (9) feet.

The pressurizer is slightly over half full of water during full power operation, with the rest of the volume filled with steam. The principal internal components of the pressurizer are its heaters in the lower section and its spray line in the upper section. Operation of the heaters and the spray maintains the steam and water at saturation temperature conditions corresponding to the desired coolant pressure. Small pressure and volume variations are accommodated by the steam volume which absorbs flow into the pressurizer and by the water volume which allows flow out of the pressurizer.

Pressurizer connections include the surge line, the spray line, safety valve nozzles, level taps, pressure taps, and 120 heater penetrations. Table 2.1-2 summarizes the pressurizer design data.

The pressurizer normal operating water volume of 600 - 800 ft^3 will satisfy the following design requirements:

1. Maintain RCS operating pressure (2250 psia).
2. Compensate for changes in coolant volume during load changes. The total coolant volume changes are kept as small as possible and within the capacities of the CVCS components.
3. Contain sufficient volume to prevent draining the pressurizer and preclude a safety injection actuation as a result of a reactor trip or loss of load event.
4. Limit the water volume to minimize the energy release and resultant containment pressure during a LOCA.
5. Prevent uncovering of the heaters by the outsurge of water following design load decreases (10% step or 5%/min. ramp).
6. Provide sufficient volume to accept the insurge following a load rejection without the water level reaching the safety valve and power-operated relief valve nozzles.

2.1.5.2 Pressurizer Theory of Operation

In order to understand how the pressurizer performs its function of maintaining RCS pressure, several basic principles must be clearly understood. First, the RCS is a closed hydraulic system, that is, its volume is constant. Second, at normal operating temperatures and pressures, water is about six (6) times as dense as steam. Third, the pressurizer is a two (2) phase saturated system. In a saturated system there is a pressure associated with each temperature. If temperature changes, then pressure must change to a new pressure corresponding to the new temperature. Fourth, assume that water is incompressible. It is not completely incompressible, but it is a good approximation. Finally, the steam will be treated as an ideal gas, which is another good approximation that will not detract from the explanation.

The ideal gas law is:

$$P = rRT$$

where:
P = pressure
r = density
R = ideal gas constant
T = temperature

Since the pressurizer is a saturated system, holding the temperature constant will hold the pressure constant. Since it is desired that the RCS be at constant pressure, the pressurizer is operated at constant temperature. Since R and T are constant, then pressure is proportional to density. The RCS is a closed system, therefore, pressure changes in the pressurizer will be transmitted to the entire RCS. In a pressurized water reactor (PWR), it is desirerable to operate the loops about 50°F subcooled, that is, about 50°F below saturation temperature. The higher temperature in the pressurizer is maintained by electrical heaters.

If the pressure decreases in the RCS for some reason, the pressure in the pressurizer will now be lower than saturation pressure for the temperature in the pressurizer. Water will boil using stored energy and energy from the heaters. When the water changes to steam, it will expand about six (6) times. The RCS and pressurizer is, however, a fixed volume so the steam will have to increase in density, and the pressure will increase.

Conversely, if RCS pressure increases, pressure will be above saturation pressure, and steam will condense. The steam will contract to about one-sixth (1/6) of its volume when it condenses to water, leaving more volume for the remaining steam at a decreased density and pressure. The condensation of the steam is aided by spraying in relatively cold water from an RCS cold leg.

It is important to note that the pressurizer acts as a surge volume for the RCS for transients and changes in steady state power. The pressurizer is designed to maintain a relatively constant pressure during all conditions using heaters and/or sprays.

2.1.5.3 Pressurizer Heaters

The pressurizer heaters function to initially form the steam bubble in the pressurizer, increase pressurizer pressure to normal operating pressure (2250 psia), and maintain normal operating pressure. Each of the 120 pressurizer heaters is an immersion type heater rated at 480 Vac and 12.5 kW. The heaters are approximately seven (7) feet long and are vertically mounted through sleeves welded in the bottom head of the pressurizer.

The heaters are separated into two (2) groups for control purposes. The first group is called the proportional group and is installed to compensate for pressurizer heat losses to ambient.

This group has 24 heaters that are divided into two (2) 150 kW banks. These heaters are called proportional heaters because their power input is proportional to the deviation of pressurizer pressure from its normal value of 2250 psia. The heaters will receive maximum power at a pressure of 2225 psia and minimum power at 2275 psia.

The backup heaters are the second group of heaters. The 96 backup heaters are divided into four (4) banks of 24 heaters (300 kW per bank). All backup banks are bistable controlled with an on point of 2200 psia and an off point of 2225 psia.

All pressurizer heaters are interlocked with low pressurizer level to prevent damage caused by uncovering the heaters. To assure sufficient pressurizer control for natural circulation flow following a loss of off-site power, the heaters are capable of being powered from the emergency buses.

2.1.5.4 Pressurizer Surge Line

The pressurizer surge line allows the pressurizer to exert its pressure onto the RCS and also allows the pressurizer to serve as a surge volume for the RCS. The surge line originates at the top of the 11 hot leg and connects to the bottom of the pressurizer through the use of a thermal sleeve that minimizes temperature induced stresses. A temperature element is installed in the surge line to alert the operators to a possible loss of spray bypass flow. The bypass flow causes a continuous circulation from the pressurizer to the RCS.

2.1.5.5 Pressurizer Spray (Figure 2.1-7)

Pressurizer spray originates at the discharge of 11A and/or 11B reactor coolant pumps and functions to decrease pressurizer pressure by condensing a portion of the steam bubble.

The spray valves are controlled by the pressurizer pressure control system (PPCS) and provide a maximum spray line flow rate of 375 gpm. The valves are full open if pressure increases to 2350 psia and close at a value of 2300 psia. Figure 2.1-8 summarizes the various pressurizer pressure setpoints. Since neither the spray valves or their control system are safety grade, no credit is taken for the termination of anticipated operational occurrences (AOOs) by the spray system in safety analysis.

A spray bypass valve parallels each spray valve and is used to maintain a continuous bypass flow of one and a half (1.5) gpm through the spray line. This bypass flow maintains the spray lines and spray nozzle close to Tc values which minimizes thermal transients on these components when the spray valves are opened. In addition, the bypass flow helps to maintain the pressurizer and RCS boron concentration at equal values. Maintaining the pressurizer concentration equal to the RCS concentration prevents reactivity changes during pressurizer outsurges. RTDs are installed in each spray line to alert the plant operators to the possibility of insufficient spray bypass flow.

In addition to the normal spray valves, the pressurizer is equipped with an auxiliary spray connection that supplies spray water from the CVCS charging pumps. This source of spray would be used during startup/shutdown operations when the RCPs are not in service or to control pressurizer pressure during natural circulation.

2.1.5.6 Pressurizer Overpressure Protection (Figure 2.1-7)

Control of pressurizer pressure provides overpressure protection for the RCS during normal operations. During transient operation, four (4) pressure relief valves provide added assurance of system overpressure protection. Two (2) of the valves are regular spring-loaded, self-actuated code safety valves and two (2) are power operated relief valves (PORVs).

The two (2) PORVs are located in two (2) parallel piping loops, connected on the inlet side to the relief valve nozzles on top of the pressurizer and on the outlet side to the piping to the quench tank. Branching off each of the PORV loops, and in parallel with the PORVs, are the lines that contain the code safety valves. All four (4) flowpaths merge into a common pipe that discharges to the quench tank.

The pressure relief system is designed such that if an abnormal incident results in a high pressure of 2400 psia, a reactor trip occurs. The high pressure reactor trip signal opens both of the PORVs. If the pressure continues to increase, one code safety valve opens at 2500 psia and a second code safety valve opens at 2565 psia. If, for some reason, a reactor trip did not occur at 2400 psia, then the PORVs remain shut and the code safety valves will provide overpressure protection for the RCS.

Power Operated Relief Valves

The PORVs operate to relieve RCS pressure at a setpoint below the setting of the code safety valves. The PORVs have remotely operated isolation valves to provide a positive shut-off capability should a relief valve become inoperable. The electrical power for both of the PORVs and the isolation valves is capable of being supplied from an emergency power source to ensure the ability to seal this possible RCS leakage path.

The PORVs are solenoid operated valves with a relieving capacity of 153,000 lbm/hr which normally relieves pressure to the quench tank when the high RCS pressure trip setpoint of 2400 psia is reached. This setting may be lowered to 400 psia to protect the reactor vessel from overpressurization during cold conditions less than 330°F. This low value set is called the minimum pressurization temperature (MPT). The PORV settings may be changed by use of two handswitches located in the MCR.

In the event of an abnormal transient which causes a sustained increase in pressurizer pressure at a rate exceeding the control capacity of the spray, a high pressure reactor trip will be reached at 2400 psia. This signal trips the reactor and opens the two PORVs which discharge steam to the quench tank to lower the system pressure.

The PORVs have sufficient capacity to:

1. Handle the maximum steam surge from a continuous control element assembly withdrawal incident starting from low power, without letdown or pressurizer spray operable, or

2. Handle the maximum steam surge from a loss of load incident at full power, with the pressurizer spray operable and a reactor trip on high pressure.

Code Safety Valves

The two pressurizer safety valves are installed to provide overpressure protection for the RCS. The valves are self-actuating and have setpoints of 2500 psia and 2565 psia. If RCS pressure increases to the safety valve setpoint, the safety valves will open and sequentially relieve the overpressure to the quench tank. The safety valves have capacities of 296,065 lbm/hr and 302,000 lbm/hr respectively. This capacity prevents RCS pressure from exceeding 110% of design pressure (ASME requirement) during AOOs.

The operational occurrence that determined the relieving capacity of the safety valves is a 100% loss of load. The following conservatisms were assumed for the analysis:

1. Loss of load without a reactor trip until the first RPS trip setpoint (pressurizer pressure high) is reached,
2. Initial reactor power is at rated thermal power,
3. No credit was taken for steam dump and bypass control system (SDBCS) actions,
4. No credit was taken for the operation of the PORVs,
5. The valves reach maximum flow capacity at 103% of design setpoint or less (3% accumulation),
6. The valves reseat at not less than 96% of the setpoint pressure (4% blowdown) and
7. The valves start to relieve within 1% of setpoint pressure (setpoint tolerance).

PORV and Code Safety Valve Instrumentation

Two (2) different instruments located downstream of the respective relief valves are installed to provide indication of an open or leaking valve.

The temperatures of the PORV and the code safety valve combined discharge lines are monitored by RTDs installed downstream of the respective valves. There is one (1) RTD in each of two (2) lines which monitors the combined discharge of one (1) PORV and one (1) code safety valve. An additional RTD is located in the PORV combined leakoff line. All three (3) RTDs send signals to the plant computer for temperature indication which can be displayed on a CRT in the MCR.

Position indication (required by NUREG-0737, "Clarification of TMI Action Plan Requirements") is provided by an acoustic monitor system (Figure 2.1-9). The system determines if any liquid or steam is flowing past the valves by utilizing an accelerometer to detect vibrations which are induced by flow in the relief valve piping. The accelerometer transmits a signal to an amplifier housed in the reactor regulating system (RRS) cabinet. Indication of each valves position is provided by a separate analog indicator on the RRS cabinet and by a digital readout on a main control board. A PORV/safety valve acoustic monitor alarm is also provided when any of the four (4) valve flow indications rises to a predetermined value.

2.1.5.7 Quench Tank (Figure 2.1-10)

The 217 ft^3 capacity quench tank receives and condenses the steam discharged by the four

(4) pressurizer relief valves. The steam is discharged beneath the water level in the quench tank preventing release of coolant activity and energy to the containment building. The quench tank is designed to prevent the discharge of the PORVs or the code safety valves from being discharged to the containment building.

During normal operation, a volume of approximately 100 ft^3 of water blanketed by a three (3) psig nitrogen pressure is maintained in the tank. This level (about 24 inches) is sufficient to reduce the necessary tank volume and pressure requirements and to accommodate the code safety valve discharge from two consecutive events: loss of load from 10% power without a concurrent loss of load reactor trip followed by a discharge caused by a continuous CEA withdrawal accident that occurs as the plant is returned to power. After receiving the discharge, the quench tank pressure will be greater than the tank relief valve setpoint (35 psig) but less than the quench tank rupture disc failure pressure (100 psig). The quench tank is not designed to receive a continuous, uncontrolled safety valve discharge. Table 2.1-3 summarizes the quench tank design data.

The quench tank sets above, and is drained to the reactor coolant drain tank (RCDT). Other connections into the quench tank are a nitrogen supply and a supply from the demineralized water system. Nitrogen is supplied to the tank to provide an inert atmosphere which precludes the buildup of an explosive hydrogen mixture. The demineralized water supply helps to maintain the proper tank inventory.

2.1.5.8 Pressurizer Level Instrumentation

As shown on Figure 2.1-7, pressurizer level is monitored by three (3) level transmitters. Two (2) of these transmitters are used by the pressurizer level control system (PLCS) and are calibrated to be accurate when the pressurizer is at normal operating temperature (653°F). The third level indicator is density compensated by pressurizer water space temperature to reflect pressurizer level at all pressurizer temperatures. This indication is used to monitor pressurizer level during shutdowns and start-ups. Pressurizer level is not a safety-related parameter.

2.1.5.9 Pressurizer Pressure Instrumentation

The pressurizer pressure instrumentation consists of four (4) safety channels, two (2) SCMM channels, two (2) control channels and two (2) low range channels.

Four (4) pressurizer pressure detectors supply signals to four (4) independent pressurizer pressure safety channels. The four channels provide narrow range (1500 - 2500 psia) signals to the RPS and the ESFAS. These signals are used by the RPS to develop the high pressure trip and PORV actuation (2400 psia), the high pressure pretrip alarm (2350 psia), the TMLP trip (1875 to 2500 psia), the TMLP pretrip alarm and a CEDS AWP signal. The ESFAS uses the input for the lo-lo pressurizer pressure safety injection actuation signal (SIAS) logic. The four (4) channels also provide signals to individual pressure indicators for each channel in the MCR.

Two (2) pressurizer pressure detectors provide wide range (0 - 4000 psia) signals to two (2) independent SCMM channels which in turn provide indication of subcooling margin and wide range pressure in the MCR.

Two (2) pressurizer pressure detectors supply narrow range signals to two (2) independent pressurizer pressure control channels. Each pressure signal is used for control of the backup heaters, the proportional heaters and the spray valve. A pressurizer pressure high/low alarm annunciated in the MCR is also supplied from the control channels. Additionally, the RRS receives a signal from the control channels , however, this signal is not currently used at Calvert Cliffs.

The remaining two (2) pressurizer pressure detectors supply low range (0-1600 psia) signals for shutdown pressure indication, SIT isolation valve automatic open (300 psia), SDC return valve automatic closure (300 psia) and input to the MPT logic circuitry.

2.1.5.10 Pressurizer Temperature Instrumentation

A single RTD is installed in the steam space of the pressurizer and provides control room indication of pressurizer temperature. Temperature indication is used by the operator to monitor pressurizer steam bubble formation as well as heatup and cooldown rates. There are no controls associated with pressurizer temperature.

2.1.6 RCS Operations

2.1.6.1 Plant Startup

For the purposes of this discussion, the initial conditions of the RCS are as follows:

1. The reactor is shutdown with a shutdown margin of 3% ΔK/K,

2. The shutdown cooling system is in service for RCS temperature control,

3. The RCS is drained to some maintenance level and

4. RCS temperature <200°F, and vented to atmosphere.

With these conditions, the first step in the startup is the filling and venting of the RCS. The RCS can be filled from the CVCS through the charging connections or from the RWT via the SDC system.

During the fill process, the pressurizer may begin to be heated using the pressurizer heaters once pressurizer level is higher than approximately 42% to save some time in the bubble formation process. The RCS will continue to be filled until the pressurizer is full and the vent is shut. The pressurizer heatup will be terminated when the pressurizer temperature reaches 300°F. A drain path from the RCS is then established and the pressurizer is drained to approximately 40% level. During the drain down the bubble will form, as indicated by a continuing decrease in level without a consequent decrease in pressure. Normal charging and letdown can then be established and the pressurizer level control system can then be placed in automatic control.

After pressurizer bubble formation is completed, pressure will be increased by continued heat addition from the pressurizer heaters. When the pressure exceeds the RCP net positive suction head (NPSH) requirements, the RCPs can be started. A pump is run in each loop for 3-5 minutes, and the RCS is vented. The pump run ensures that the air in the top of the steam generator U-tubes is swept out.

After venting operations have been completed, three (3) RCPs are placed in service and the heatup of the RCS is begun. Once the RCPs are running, the SDC system is shutdown and aligned to its emergency lineup. RCS pressure is increased as RCS temperature increases. During the RCS heatup, letdown flow will be increased to compensate for RCS expansion and to maintain pressurizer level.

Before the RCS pressure goes above 300 psia, the SIT outlet valves are opened. When temperature exceeds 500°F, the fourth RCP is started. The final step involves placing the pressurizer pressure controls in automatic at 2250 psia.

2.1.6.2 Plant Shutdown

After the reactor is shutdown, a cooldown and depressurization of the RCS is started. RCS temperature is reduced by stopping one RCP in each loop and dumping steam from the steam generators to the main condenser. Makeup from the CVCS compensates for RCS volume contractions during the cooldown. RCS pressure is reduced by manual control of the pressurizer spray valves. When temperature has been reduced to less than 300°F and pressure is at or less than 260 psia, the SDC system is placed in service. The remaining RCPs are stopped. Further temperature reduction is accomplished by the SDC system while the auxiliary spray is used to lower pressurizer pressure. These systems will be used to achieve the desired pressurizer pressure and RCS temperature.

2.1.7 RCS Low Temperature

To provide overpressure protection for the reactor vessel during cold plant conditions (Tc less than 330°F), the relief setting of the PORVs is changed from a 2400 psia setting (normal operating setting) to a setting of 400 psia. When Tc decreases to 330°F and the RCS pressure is less than 400 psia, MPT enable/normal handswitches are placed in the enable position. The handswitches are located in the MCR and align the MPT logic circuitry to provide alarm and control functions. The alarm functions advise the operator when to enable or disable the MPT protective functions. An additional alarm will warn the operators when the RCS pressure is greater than or equal to 370 psia and RCS temperature is less than 330°F or a bad quality exists on either the temperature input or pressure inputs to the circuit. The additional alarm will warn operators of improper pressurizer heater operation, faulty charging and letdown operation, improper HPSI pump operation or plant computer failure.

2.1.8 Saturation Monitors (Figure 2.1-11)

A typical saturation monitor consists of a microprocessor with the steam tables burned into a read only memory (ROM). RCS temperatures and pressures are supplied to the processor and are compared with saturation values. If the RCS temperature is within 30°F of saturation an alarm is generated. The saturation calculation is conservative because the temperature inputs are high-selected, while the pressure inputs are low selected. The temperature inputs range from 0-700°F and a pressure range of 0-4000 psia is used. Saturation monitors are redundant and powered from vital AC sources.

2.1.9 RCS High Point Vents (Figure 2.1-12)

The transfer of heat from the core to the steam generators is necessary to prevent core damage in a small break loss of coolant accident because of the low values of emergency core cooling flows. Since the RCPs are powered from non-vital busses, forced circulation is not guaranteed. Therefore, natural circulation is required for core cooling.

Since non-condensable gases from core damage, SIT injection, and RWT injections could block the natural circulation flowpath high point vents have been added to the RCS design.

2.1.10 Reactor Vessel Level Indication (Figure 2.1-13)

The Combustion Engineering reactor vessel level indication system (RVLIS) consists of heated junction thermocouples located at eleven different axial positions between the reactor vessel head and the bottom of the fuel assemblies. Two (2) sensors are located in the upper head, three (3) sensors are located in the upper guide structure, and six (6) sensors are located in a fuel assembly.

The basic principle of RVLIS operation is the detection of a ΔT between adjacent heated and unheated thermocouples. Each of the eleven sensors consists of a chromel-alumel thermocouple located near a heater and another chromel-alumel thermocouple positioned away from the heater. As steam replaces liquid in the core, the heat transfer from the heated thermocouple drops. This creates a large ΔT between the heated and unheated thermocouples. The large ΔT is used to indicate a level change. Each of the heated junction thermocouple sensors is shielded to avoid overcooling due to direct water contact during two phase fluid conditions. Vessel level indication is supplied to the safety parameter display system and a digital display in the control room.

2.1.11 PRA Insights

The PORVs are used to limit the primary pressure on transients in order to prevent the safety valves from lifting. The pressurizer PORVs are also used to remove heat from the core by once through core cooling if no other methods of heat removal are available.

The failure of the PORVs are present in several accident sequences which lead to core damage (9% of the core damage frequency). There are two general failure modes for the relief valves.

First, the failure of the PORVs to close when required leads to the need for recirculation cooling of the reactor, and the subsequent failure of the recirculation mode of the emergency core cooling systems (ECCS) results in core damage.

Second, the failure of the PORVs to open when required for once through reactor core cooling. This failure of heat removal results in core damage. Probable causes of a loss of the PORVs are:

1. Failure to open on demand,
2. Failure of the power supply to the valves,
3. Failure of the block valve to close to isolate a stuck open PORV or
4. Failure of a closed block valve to open when feed and bleed core cooling is necessary.

NUREG 1150 ("Severe Accident Risks: An Assessment For Five U.S. Nuclear Power Plants") studies on importance measures have shown that the PORVs are not a major contributor to risk achievement or risk reduction.

2.1.12 Summary

The RCS consists of the reactor vessel, steam generators, reactor coolant pumps, and interconnecting piping. The RCS is arranged in two heat transport loops with each loop containing one steam generator and two reactor coolant pumps. The RCS has a design pressure of 2500 psia and a design temperature of 650°F and serves as the second barrier to the escape of fission products to the public.

Penetrations into the RCS include thermowells for temperature indications, pressurizer surge and spray connections, CVCS letdown and charging connections, shutdown cooling suction, and emergency core cooling injection connections.

The pressurizer functions to maintain the RCS in a subcooled condition and to provide for temperature induced volume changes. Pressurizer pressure is controlled by the use of electrical heaters to increase pressure and pressurizer spray to decrease pressure. Overpressure protection for the RCS is ensured by two (2) code safety valves and two (2) PORVs located on the top of the pressurizer.

RCS temperature along with pressurizer pressure instrumentation is supplied to the RPS for the generation of reactor trips. In addition, low pressure is used to actuate emergency core cooling. Separate RCS RTDs, pressurizer pressure transmitters, and pressurizer level transmitters supply signals to the RRS, PPCS, and the PLCS. RCS flow is determined by measuring the differential pressure across the Steam Generators.

TABLE 2.1-1
RCS Design Parameters

Design thermal power, MW	2700
Btu/hr	9.213E6
Design Pressure, psia	2500
Design temperature (except pressurizer), °F	650
Number of loops	2
Pipe size, ID/wall, in.	
reactor outlet	42 w/o clad
reactor inlet	30 w/o clad
surge line, nominal	12 w/o clad
Coolant flow rate, lbm/hr	122E6
velocity, hot leg, ft/s	42
velocity, cold leg, ft/s	37
Cold leg temperature, °F	548
Average temperature, °F	572.5
Hot leg temperature, °F	599.4
Normal operating pressure, psia	2250
System water volume (w/o pressurizer), cu.ft.	9601
Pressurizer water volume, cu.ft.	800
Pressurizer steam volume, cu.ft.	700
Hydrostatic test pressure of RCS components at 100 °F (except RCP), psia	3125

TABLE 2.1-2

Pressurizer Design Parameters

Design pressure, psia	2500
Design temperature, °F	700
Normal operating pressure, psia	2250
Normal operating temperature, °F	653
Internal free volume, cu.ft.	1500
Design water volume, cu.ft.	600 - 800
Design steam volume, cu.ft.	700 - 900
Installed heater capacity, kW	1500
Spray flow, maximum, gpm	375
Spray flow, continuous, gpm	1.5
Nozzles	
Surge line, nominal, in.	12
Safety valves and PORVs, ID/in.	4
Spray, nominal, ijn.	4
Heaters, OD/ın.	0.875
Instruments	
Level, nominal, in.	1
Temperature, nominal, in.	1
Pressure, nominal, in.	1
Dimensions	
Overall length, including skirt and spray nozzle, in.	441 3/8
Outside diameter, in.	106 ½
Inside diameter, in.	95 9/16
Cladding thickness, minimum, in.	1/8
Dry weight, including heaters, lbs.	206,000
Flooded weight, including heaters, lbs.	302,200

TABLE 2.1-3
Quench Tank Design Parameters

Design pressure, psig	100
Design temperature, °F	350
Normal operating pressure, psig	3
Internal volume, cu.ft.	217
Normal indicated water level, in.	24
Blanket gas	Nitrogen
Manway (1 ea.), ID, in.	16
Nozzles	
Pressurizer discharge, nominal, in.	10
Demineralized water, in.	2
Rupture disc, in.	18
Drain, in.	2
Temperature instrument, in.	1
Level instrument, in.	1/2
Vent, in.	11/2
Dimensions	
Overall length, in.	144 3/8
Outside diameter, in.	60

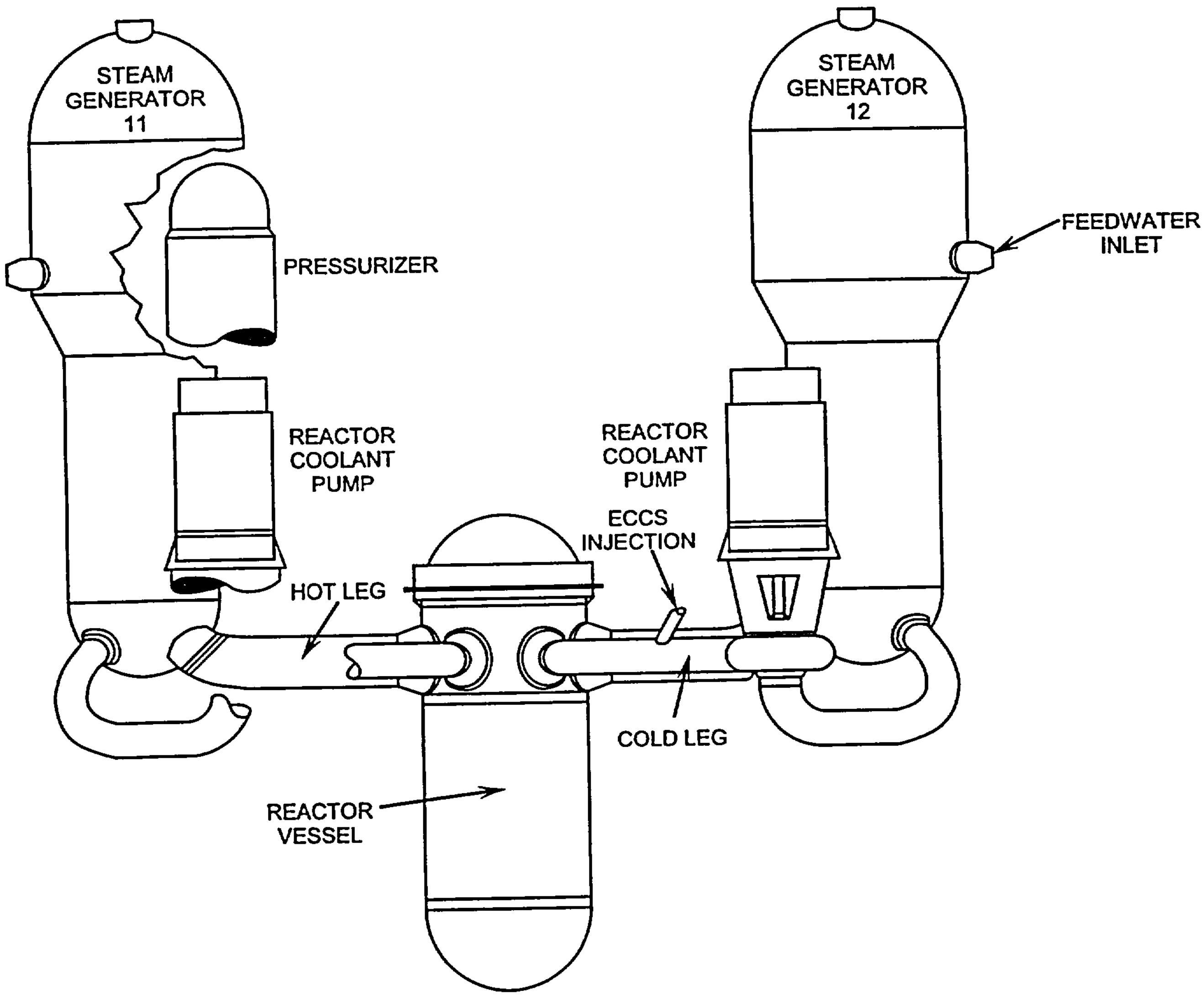

Figure 2.1-1 RCS - Elevation View

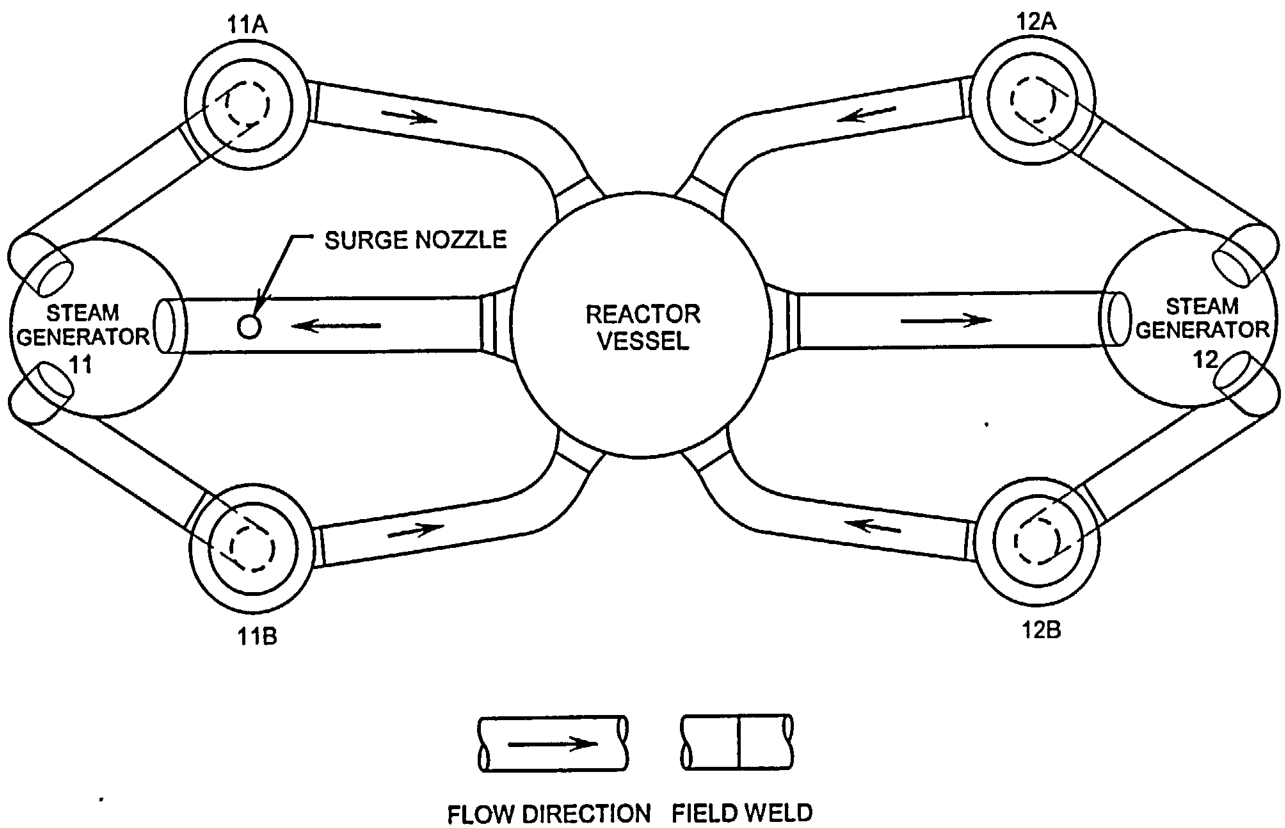

Figure 2.1-2 RCS - Plan View

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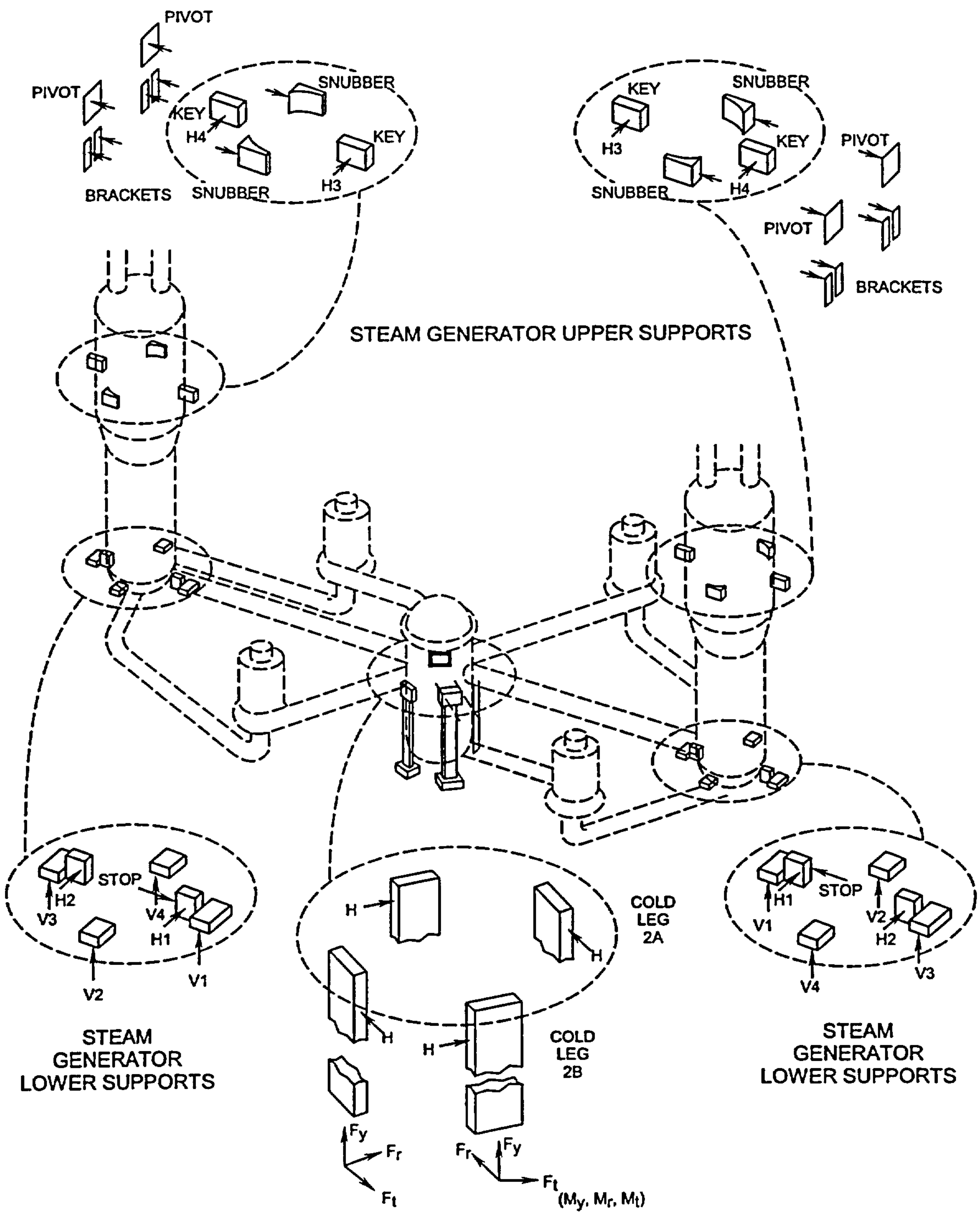

Figure 2 1-3 RCS Supports (Typical)

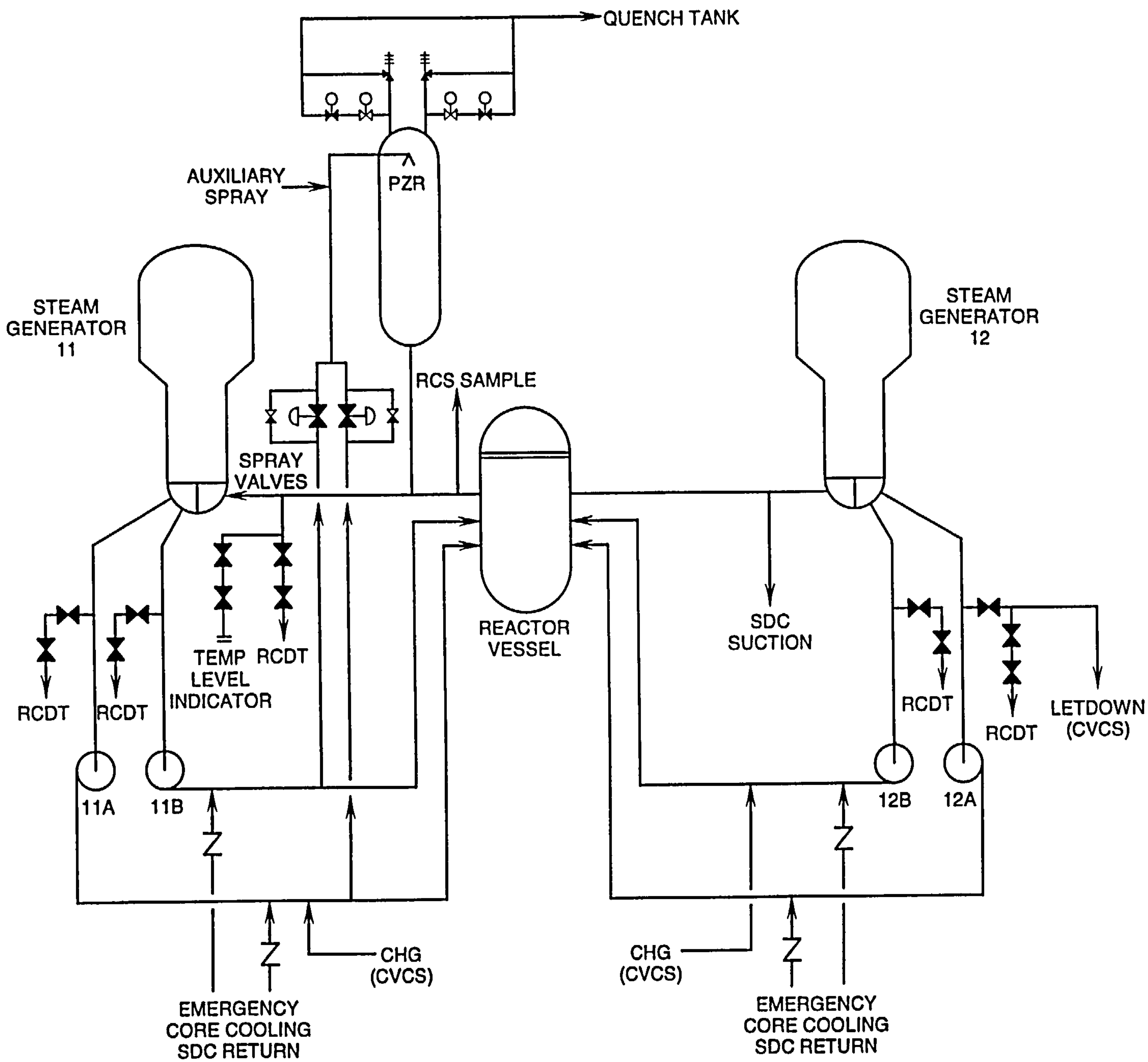

Figure 2.1-4 RCS Flow Diagram

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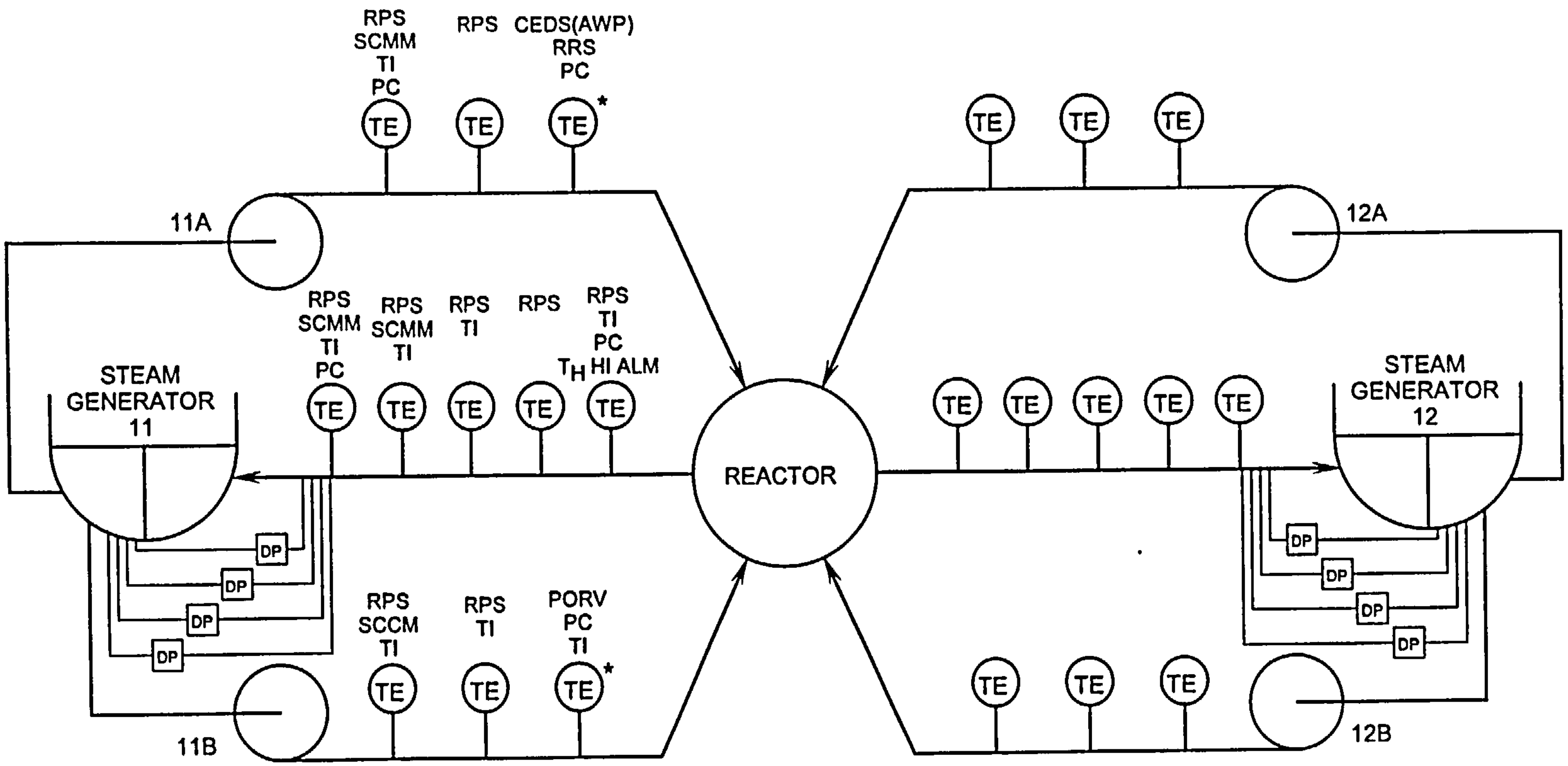


*SUPPLY THROUGH A SELECTOR SWITCH

RPS - Reactor Protection System
SCMM - Subcooled Margin Monitor
TI - Temperature Indication
PC - Plant Computer
CEDS - Control Element Drive System
AWP - Automatic Withdrawal Prohibit
RRS - Reactor Regulating System

Figure 2.1-5 RCS Instrumentation

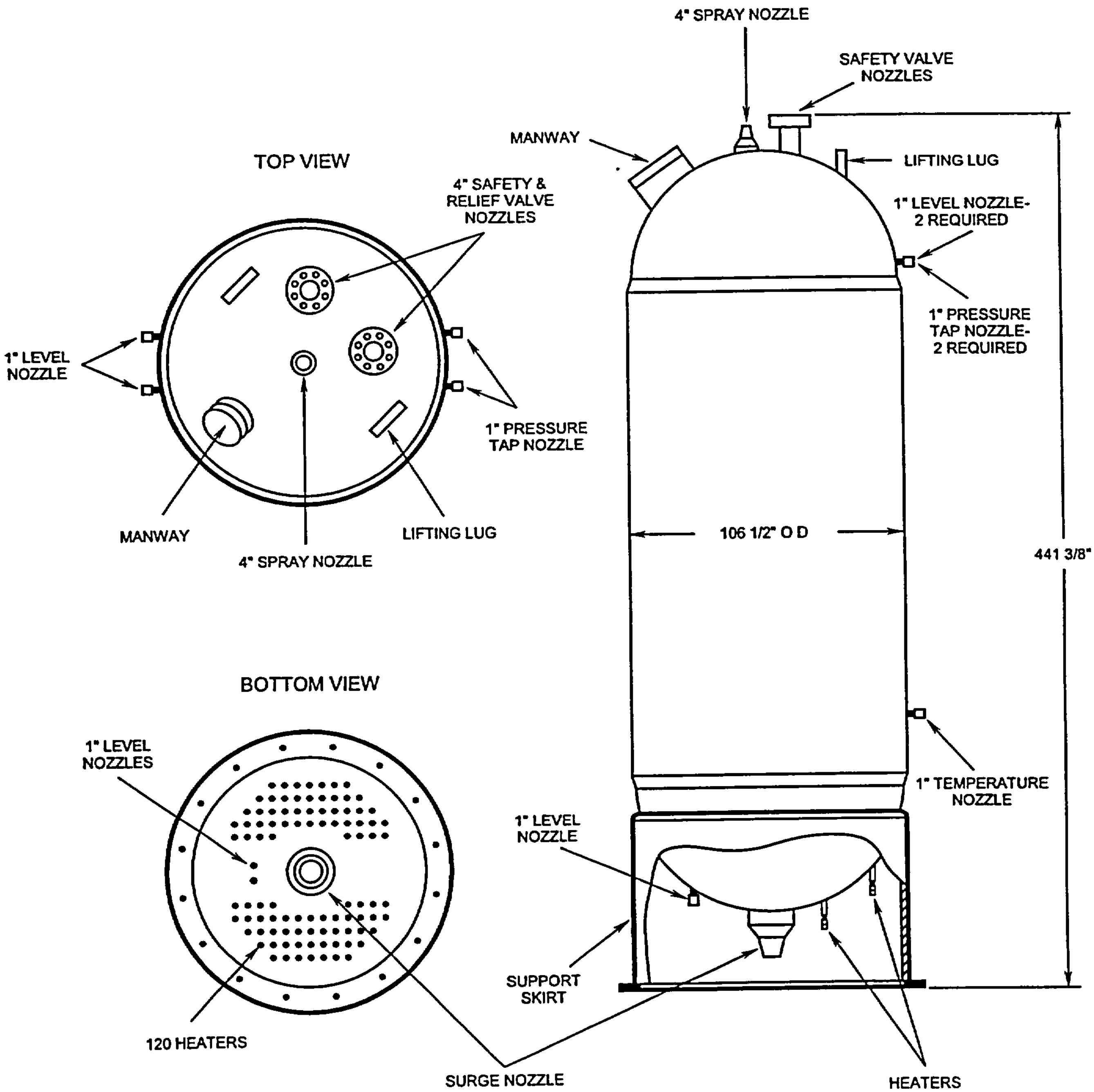
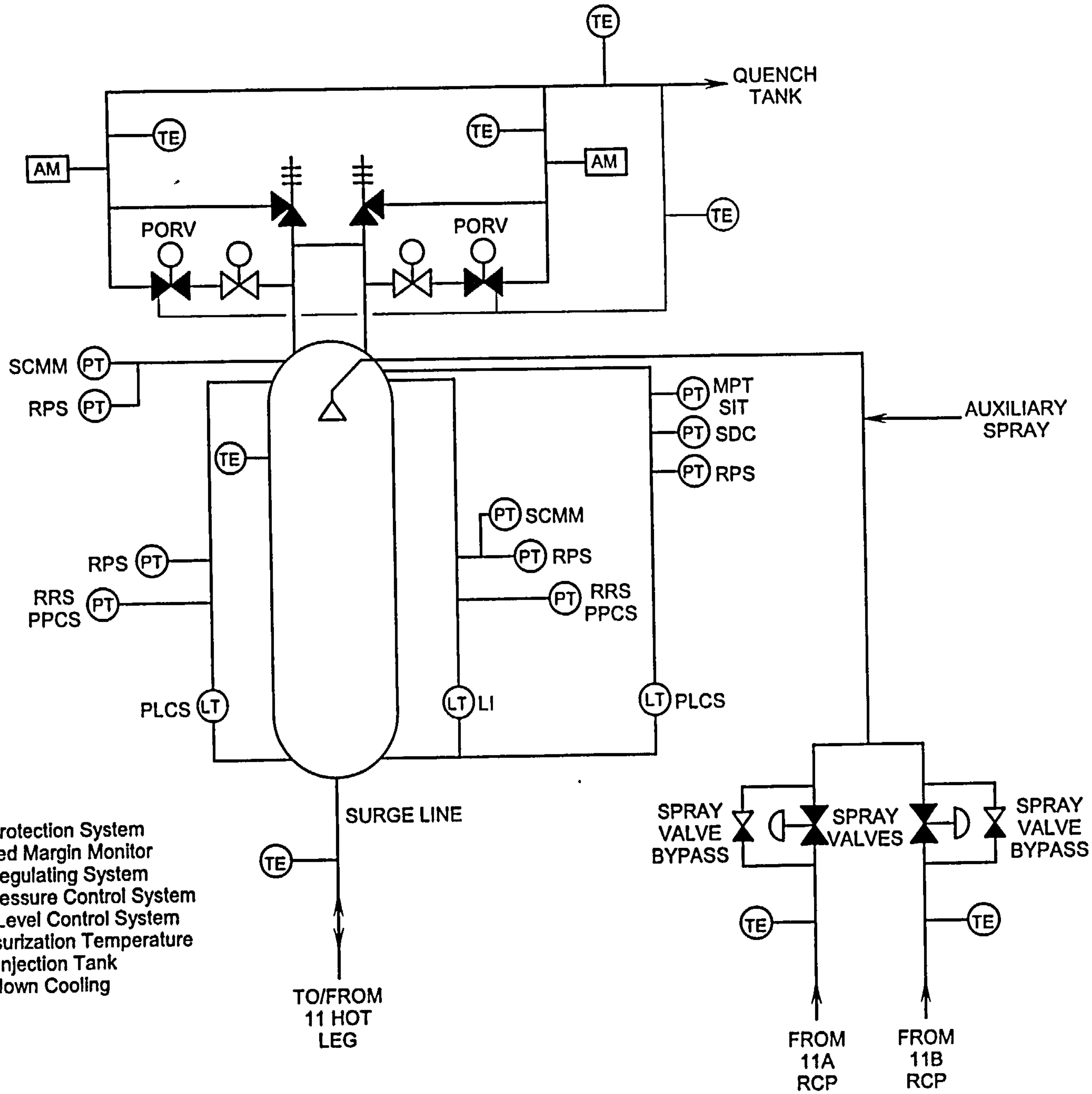


Figure 2.1-6 Pressurizer



RPS - Reactor Protection System
SCMM - Subcooled Margin Monitor
RRS - Reactor Regulating System
PPCS - Pressurizer Pressure Control System
PLCS - Pressurizer Level Control System
MPT - Minimum Pressurization Temperature
SIT - Safety Injection Tank
SDC - Shutdown Cooling

Figure 2.1-7 Pressurizer Piping Diagram

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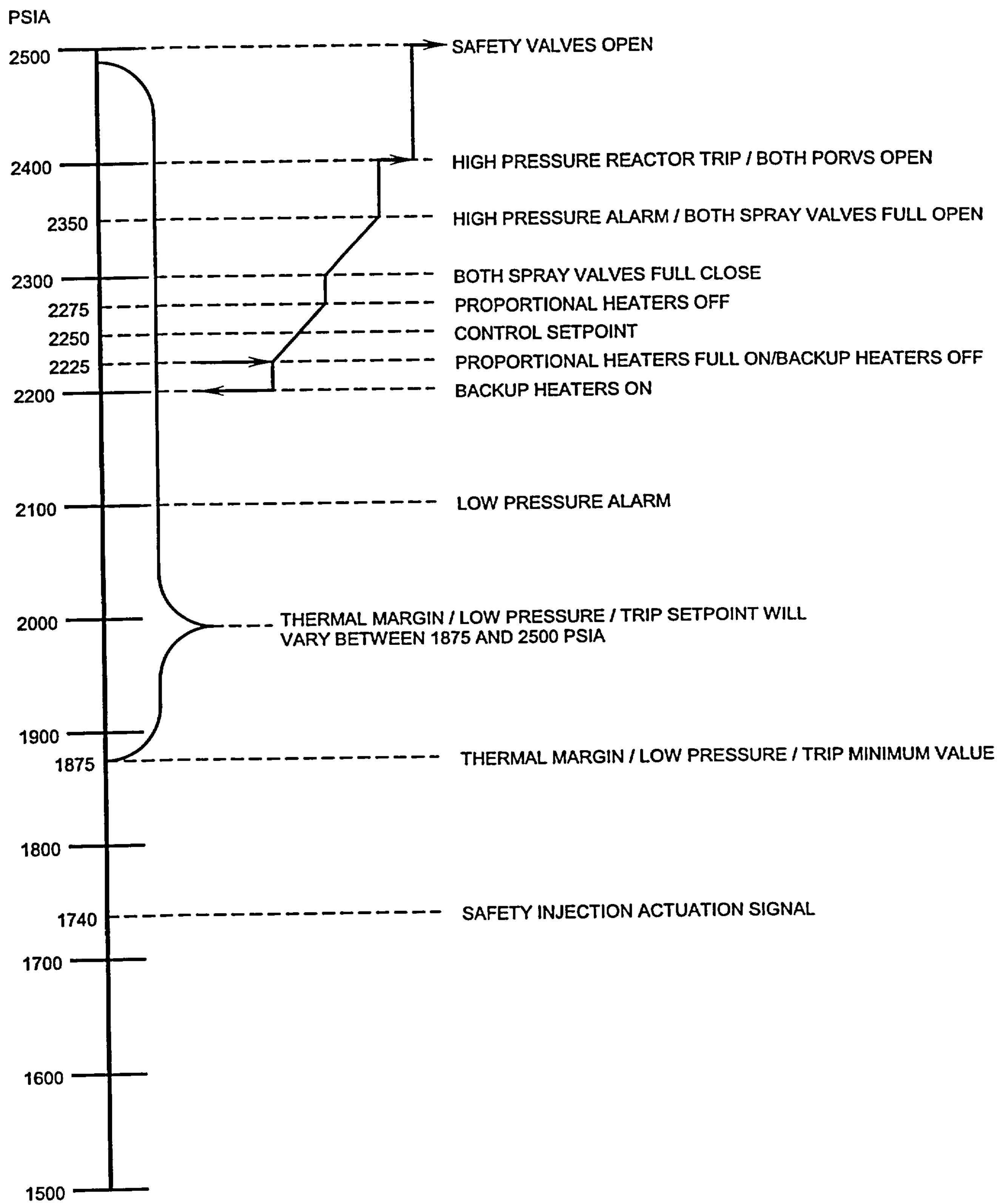

Figure 2.1-8 Pressurizer Pressure Program

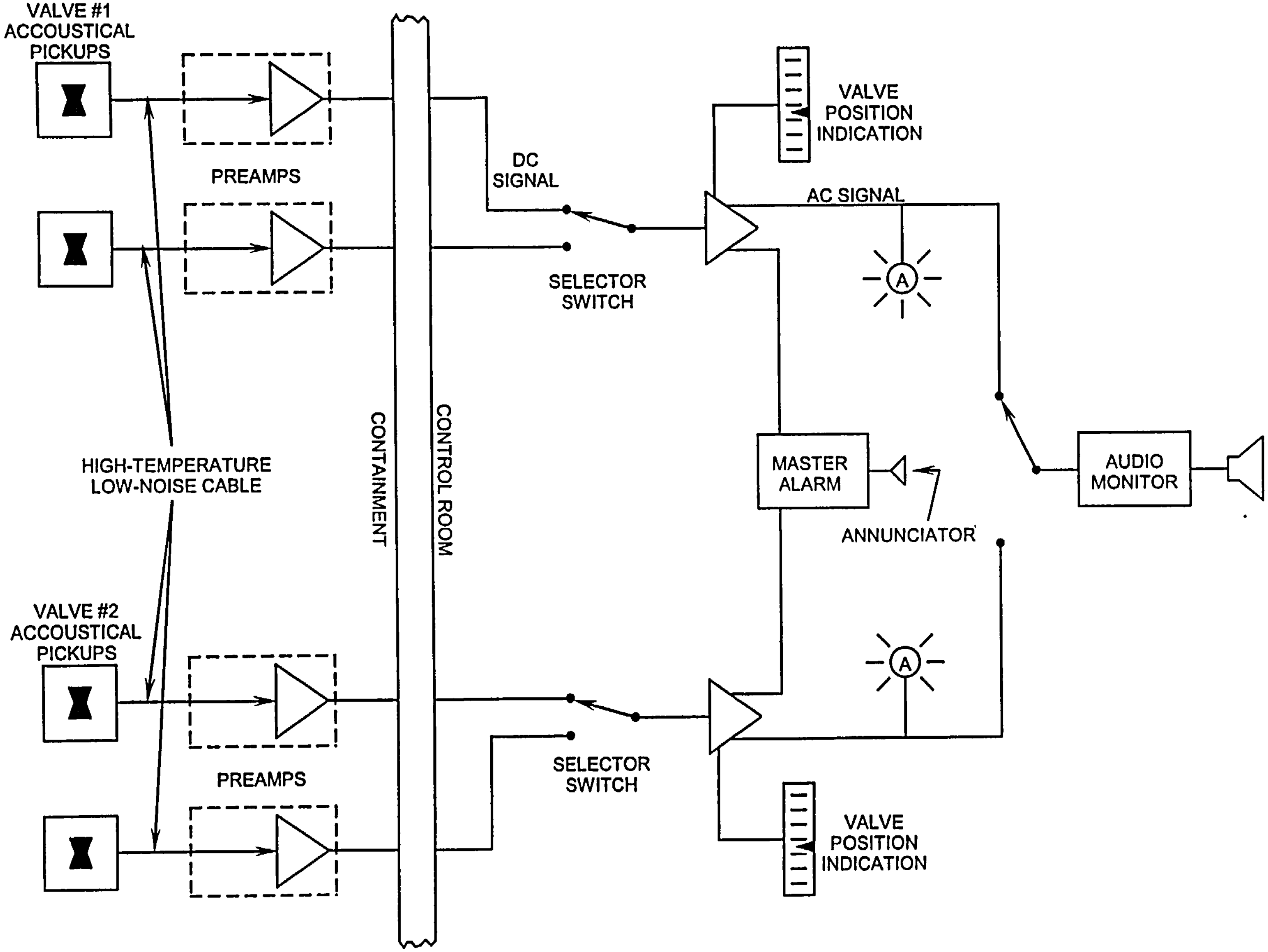

Figure 2.1-9 Accoustical Valve Monitoring

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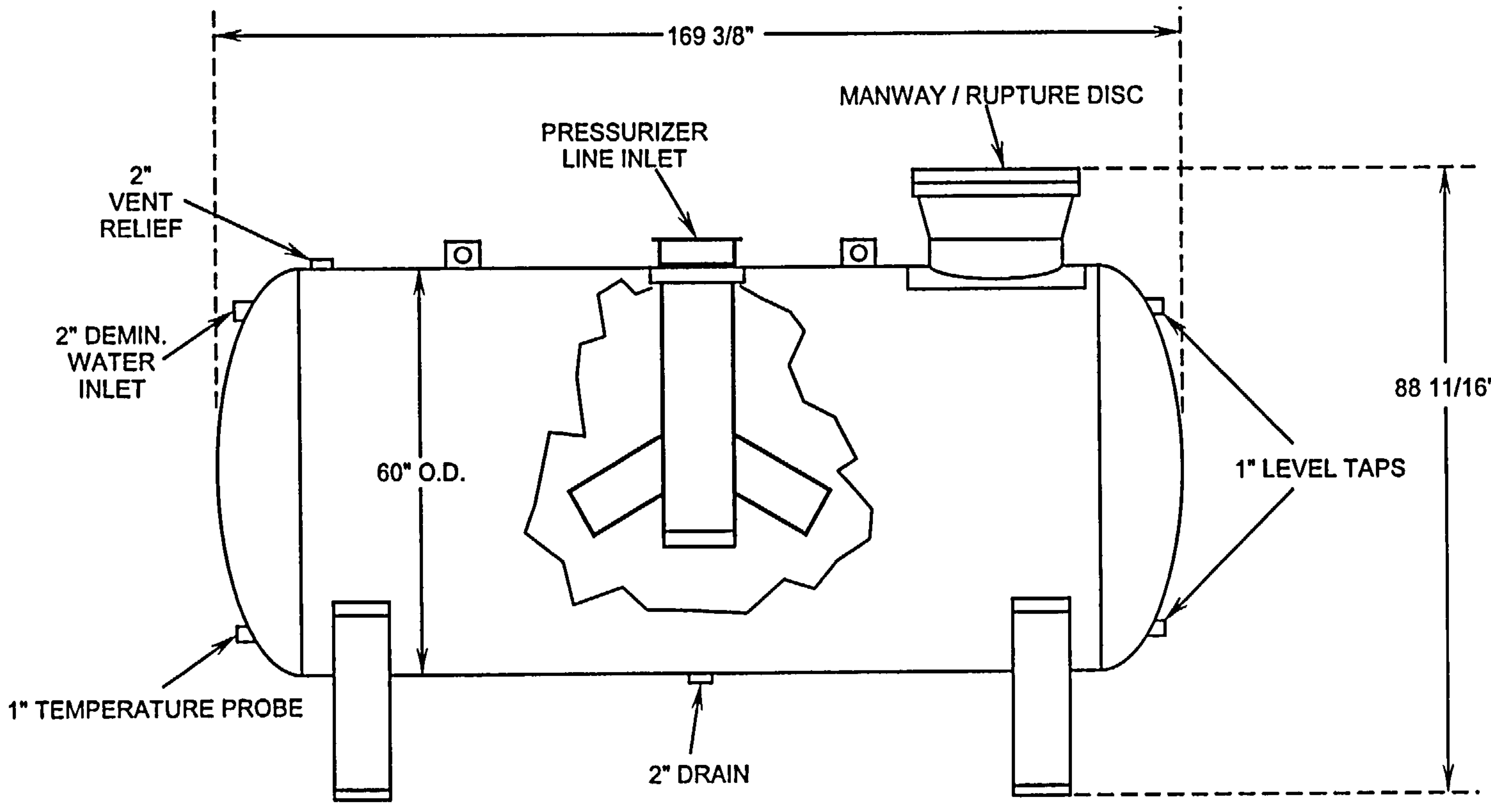

Figure 2.1-10 Quench Tank

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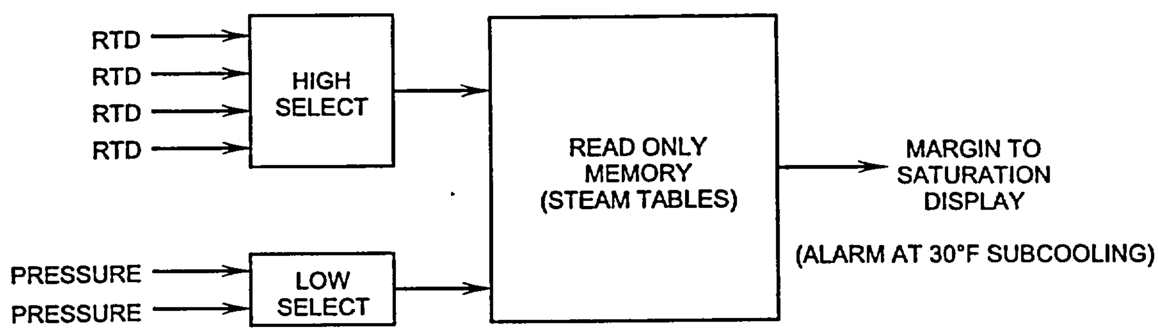
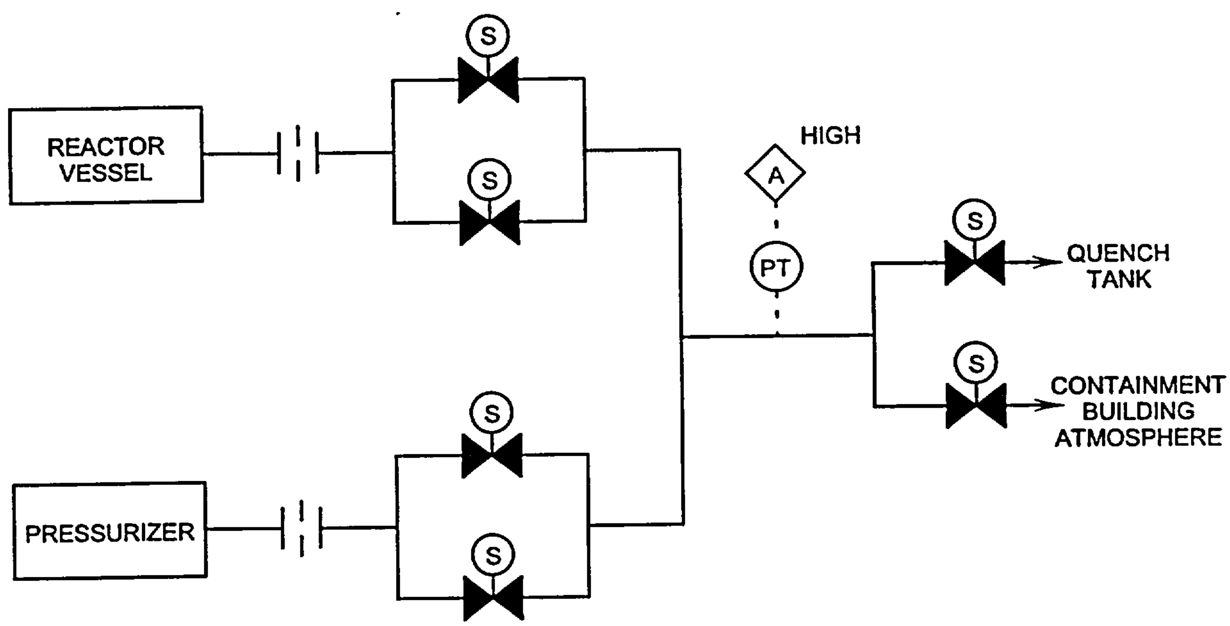


Figure 2.1-11 Saturation Monitor



ALL VALVES ARE LOCKED CLOSED

Figure 2.1-12 High Point Vents

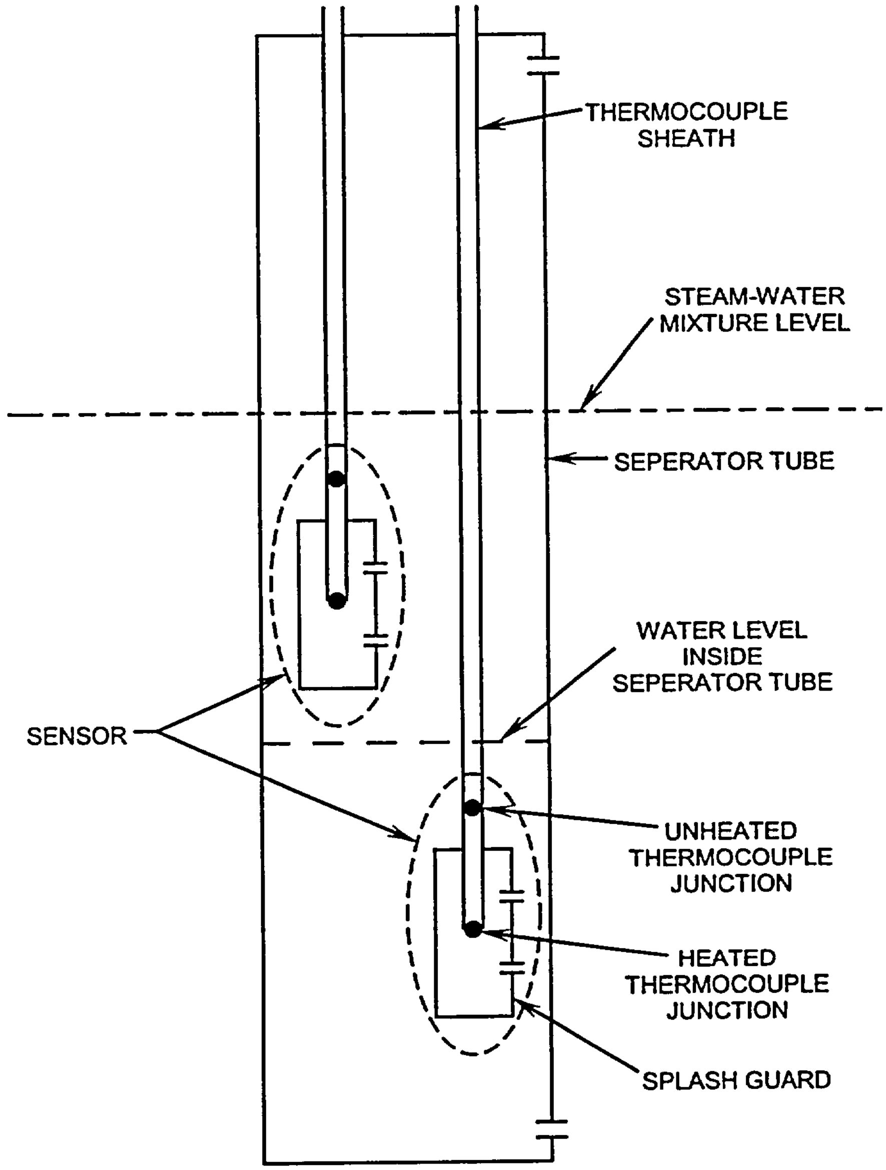


Figure 2.1-13 Reactor Vessel Level Indication

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2.2 REACTOR COOLANT PUMPS

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2.2 REACTOR COOLANT PUMPS

Learning Objectives:

1. State the purposes of the reactor coolant pump (RCP).

2. Describe the flow paths through the RCP.

3. Explain how the RCP seal minimizes leakage of reactor coolant to the containment building atmosphere.

4. State the safety-related function of the RCP motor flywheel.

5. State the purposes of the RCP motor anti-reverse rotation mechanism.

6. State the purpose of the RCP instrumentation.

2.2.1 Reactor Coolant Pump Purposes

The purposes of the RCPs are:

1. To provide the forced circulation of reactor coolant for the removal of core heat.

2. To provide energy to heat up the RCS from ambient temperature to greater than the minimum temperature for criticality prior to reactor startup.

2.2.2 Introduction

The four (4) RCPs circulate reactor coolant through the core at a rate of 122×10^6 lbm/hr. This flow rate provides heat removal for the 2700 megawatt rating of the core. Each reactor coolant pump is a vertical shaft, single suction, single stage centrifugal pump with a flow rate of 81,200 gpm (Table 2.2-2). The pump is driven by a squirrel cage induction motor powered from the 13.8 kV non-vital ac distribution system. All four pumps must be running for critical operations. Figure 2.2.1 illustrates the pump characteristics.

2.2.3 Pump Construction (Figure 2.2-2)

The RCPs are vertical shaft, single-suction, single-stage, centrifugal pumps which are manufactured by Byron Jackson, a division of Borg Warner. The main components of the pump are the pump case assembly, the pump cover and heat exchanger assembly, the driver mount, the rotating element assembly (shaft, impeller, and coupling) and the shaft seal assembly.

The pump case assembly consists of the pump case, the case wear ring, and various gaskets and fasteners. The pump case forms the volute of the pump which is designed to convert the velocity head of the coolant discharged from the pump impeller into pressure head potential. The casing wear ring is an interface medium between the pump impeller and the casing. Because the wear ring metal is not as hard as the metal from which the impeller is made, the wear ring preferentially wears during use, thereby protecting the integrity of both the impeller and the casing.

The pump cover and heat exchanger assembly consists of a metal enclosure located above the pump impeller and supports the components above it (the heat exchanger and the hydrostatic bearing). The heat exchanger's tubes are segregated into two (2) banks which are piped in parallel and arranged concentrically about the pump shaft. The heat exchanger tubes consist of a pipe of smaller diameter contained within a pipe of a larger diameter so that reactor coolant, which is at a high pressure, can flow through the inner pipe and component cooling water (CCW), which is at a lower pressure, can flow through the annular region between the inner and outer pipes.

The hydrostatic bearing positions the pump shaft in the horizontal direction and is self aligning. Bearing self alignment is achieved by directing impeller discharge pressure against the surface of the bearing journal balance plate which moves the bearing journal in the horizontal direction. The hydrostatic bearing is mechanically restrained in the vertical direction by attaching it to the pump cover.

Metallic O-rings and studs provide a seal between the pump casing and the casing cover. A passage between the two (2) O-rings is connected to piping which is routed to the containment sump. If the inside O-ring fails, hot reactor coolant will flow to a resistance temperature detector (RTD) that is located in the drain path, causing an increased output from the RTD, resulting in an alarm in the control room. The outside O-ring prevents leakage from the RCS in this event.

The rotating element assembly consists of the pump shaft with its bearing journal, the impeller, the auxiliary impeller, the recirculating impeller, the pump half coupling, the thrust disc, the motor half coupling and the rotating pump seal package components. The pump shaft is the principal rotating element to which the other components are attached. The pump shaft's motion is restrained in the horizontal direction by the bearing journal, which is attached to the shaft immediately above the pump auxiliary impeller.

The auxiliary impeller supplies pressure to the self-aligning journal bearing and a small amount of flow to the pump seals via the thermal barrier. The pump half coupling, motor half coupling, and thrust disc are located at the top of the pump shaft. They connect the pump rotating element assembly to the motor shaft.

When assembled for operation, the coupling components of the rotating element assembly transmit torque from the motor to the pump, and transfer vertical thrust from the pump shaft to the motor thrust bearing. The spacer, which connects the motor half coupling to the pump half coupling, can be removed to permit access to the shaft seal without removal of the motor. The setting of the adjusting cap and the thrust disc/spacer ring determine the axial alignment of the rotating components.

2.2.4 Reactor Coolant Pump Seal Assembly (Figure 2.2-3)

The RCP seal assembly consists of a concentric tube heat exchanger, a shaft mounted auxiliary impeller, four (4) mechanical seals, and seal pressure breakdown devices. The seal assembly functions to minimize the leakage of reactor coolant past the shaft and into the containment building.

The mechanical seals are lubricated and cooled by 1.0 gpm of controlled reactor coolant bleed-off (CBO). Reactor coolant enters the seal area through the region between the labyrinth seal/thermal barrier and the shaft. In this process, some of the thermal energy contained in the reactor coolant is removed by CCW supplied to this region of the pump. The labyrinth seals reduce the RCS working pressure, which was increased by the main and auxiliary impellers, back to RCS pressure (2250) to minimize the mechanical seal wear which would otherwise occur if the seals were operated at a higher pressure.

The seal package for the RCP consists of four (4) mechanical seals. Three (3) of these seals are used to contain reactor coolant pressure while the fourth is used as a vapor seal. Each of the four (4) seals is able to withstand full system pressure. Each mechanical seal consists of a shaft mounted titanium carbide rotating face and a stationary graphite face.

Springs on the rotating face keep the seal faces aligned. Breakdown orifices are installed in parallel with the first three (3) seals and are used to set the operating differential pressure (~700 psid) of each seal. Of the one (1) gallon per minute that leaves the recirculation area, approximately 99% passes through the orifice breakdown devices, and the other 1% passes between the seal faces for lubrication.

Figure 2.2-4 provides a simplified diagram of the pump seals and breakdown devices. As shown on the drawing, one (1) gpm of flow enters the lower seal and breakdown device at RCS pressure (2250 psia). The majority of flow passes through the device to the middle seal area and the remainder passes between the seal faces of the lower seal. Water at a pressure of ~1500 psia travels in the same manner through the middle seal. Finally, the inlet pressure to the upper seal is ~750 psia and the flow through this seal is identical to the flow through the lower and middle seals. Most of the water that passes through the seals is collected above the upper seal through the CBO line and routed to the volume control tank (VCT). Approximately three-tenths (.3) gallons per hour will pass between the rotating and stationary faces of the vapor seal and into the containment sump. As described above, the leakage up the shaft is forced to take a tortuous path through the seal faces thus the quantity of leakage is minimized.

The RCP seal assembly description provided above should be considered to be typical of a Byron Jackson pump installation. Competitive forces in the market place have brought some amount of choice to utilities seeking promises of improved seal performance. The inspector should determine the origin, construction and operational features of the seals used at their individual locations

2.2.5 Flow Paths Through the RCP

There are four (4) flow paths through each RCP:

1. RCS flow to the reactor vessel through the RCP impeller from the steam generator

2. RCS flow through the auxiliary impeller, mounted on the back of the RCP impeller, to the RCP journal bearing and along the shaft, past the thermal barrier to the seal cavity,

3. Seal cavity recirculation flow generated by the seal water recirculating impeller which flows from the seal cavity to the inner pipe of the integral heat exchanger tubes and is then discharged to the seal pressure breakdown devices and the seals themselves, and

4. The CCW flow, which is divided into two streams: one of which cools the thermal barrier and the second of which passes through the annular region between the inside and outside pipes that form the integral heat exchanger tubes, thereby removing heat from the seal area recirculation flow.

A portion of the seal cavity flow passes through the pressure breakdown devices, bypassing the seal faces, and is discharged as CBO to either theVCT or the reactor coolant drain tank (RCDT).

The seal area recirculating impeller delivers approximately 40 gpm of water to the integral heat exchanger. The recirculating water flow passes upward in a parallel path through the inner diameter integral heat exchanger tubes, which are arranged in two concentric tube banks. CCW flows in a downward direction through the annular region between the inner and outer diameter pipes which comprise the integral heat exchanger tubes, thereby removing heat from the recirculating water flow stream. The CCW from the thermal barrier and integral heat exchanger are combined at the heat exchanger's discharge, and the combined flow is returned to a CCW return header.

The recirculating water flow, which leaves the heat exchanger inside the tube bank, enters the seal cavity between the cover and the middle pressure breakdown device. The water flows toward the recirculating impeller past the low pressure breakdown device and is recirculated into the inner heat exchanger tubes. The recirculating water flow, which is cooled in the heat exchanger outside tubes, is directed into the lower pressure breakdown device where it is forced by differential pressure through three (3) stages of pressure breakdown and cools the three (3) upper seals as it flows out of the CBO.

The quantity of water which passes through the CBO discharge is approximately one (1) gpm. CBO past the third seal, is ducted by a header to the VCT. Leakage past the fourth seal, the vapor seal, is directed to the containment sump. Less than three-tenths (0.3) gallons per hour pass through this last seal.

Water from CCW cools the RCP and pump motor. CCW flow rate to each reactor coolant pump is 200 gpm, of which 45 gpm is directed to the seal area and 155 gpm is directed to the RCP motor. Both the upper and lower oil reservoirs in the pump motor have oil-to-water heat exchangers which are also cooled by CCW. The seal area cooling water is further subdivided into two (2) streams:

1. Seventeen gpm of CCW is used to cool the thermal barrier area, the labyrinth passageway through which the one (1) gpm CBO enters the seal cavity area and

2. Twenty-eight gpm of CCW is directed to the integral heat exchanger tubes through which the approximately 40 gpm of recirculation water passes.

CCW enters the integral heat exchanger at the top of the heat exchanger's inside and outside tube banks and flows in a downward direction through the annular region formed by the heat exchanger's double pipe tube arrangement. Recirculating water, contained in the inner pipe of the heat exchanger tubing, gives up heat energy to the cooler CCW. The integral heat exchanger is configured as a counter flow heat exchanger arrangement and the recirculating water flows in a direction opposite to that of the CCW. The counter flow configuration is more efficient than a parallel flow arrangement which allows a smaller heat exchanger to be used. The counter flow arrangement also minimizes the temperature differential between the recirculating water and component cooling water at the heat exchanger inlet, thereby reducing thermal shock to the heat exchanger components in this region.

2.2.6 Reactor Coolant Pump Motor (Figure 2.2-5)

The RCP motor is a vertical, solid shaft, three phase, squirrel cage induction ac motor. The major components of the motor are the rotor, stator, two radial bearings, a thrust bearing, flywheel, anti-reverse rotation device, and the motor air cooler.

The induction rotor and stator are of conventional design with a rotational speed of 900 rpm and are rated at 6000 horsepower. The motor is cooled by a rotor attached fan and the motor air cooler. The fan is mounted at the bottom of the rotor and draws containment building air across the motor air cooler. The air is discharged out the top of the motor. A CCW flow of 155 gpm cools the motor inlet air.

The motor radial bearings maintain rotor alignment and are oil lubricated by a self contained oil reservoir and the rotational action of the bearing race. The thrust bearing is a Kingsbury double acting thrust bearing and along with the pump hydrostatic radial bearing supports the weight of the motor/pump. In addition, the thrust bearing compensates for thrusts caused by the hydraulic forces when the pump is operating. A high pressure oil lift pump forces oil under the thrust shoes to reduce torque during start-up. A low pressure oil pump is used to lubricate the anti-reverse rotation device during pump starting. Both pumps are stopped once the RCP reaches rated speed.

The RCP flywheel is installed on the motor rotor and functions to increase pump coast down time. The increase in flow coast down improves the DNBR after a complete loss of pumping power event. Since this component is involved in reactor protection analysis, it is safety related and subject to integrity inspections.

The final motor component is the anti-reverse rotation device which serves two (2) purposes. First, the anti-reverse rotation device minimizes motor starting torque. If a start of the pump is attempted when the pump is rotating in the reverse direction, the pump must be decelerated to zero speed and then accelerated in the correct direction to normal speed. The current required to decelerate and accelerate could cause damage to the motor and associated electrical cabling. Second, the anti-reverse rotation device minimizes reverse flow through an idle pump.

2.2.7 RCP Instrumentation (Figure 2.2.6)

The four (4) RCPs are equipped with instrumentation to detect and warn the operator of impending failure or abnormal operating conditions.

2.2.7.1 Pump Instrumentation

RCP instrumentation includes seal pressure and temperature, CBO flow and temperature and pump vibration indication.

The RCP seal system is monitored by three (3) pressure detectors and one temperature detector. The RCP shaft seal assembly consists of four (4) mechanical seals. The three (3) full-pressure seals are mounted in series and each has a pressure detector that senses the pressure below the respective seal. The lower seal pressure detector is not indicated in the main control room (MCR) since it should equal RCS pressure, however, a signal is sent to the plant computer. The middle and upper seal pressure detectors send signals to individual pressure indicators in the MCR as well as to the plant computer. The middle seal and upper seal pressure detectors actuate respective RCP seal temperature / pressure alarms in the MCR.

These indications can be used by the operating staff to determine seal failures. The following table gives typical pressures for various seal failures, assuming a normal RCS pressure of 2250 psia.

Table 2.2-1 Seal Pressures

Affected Seal	Lower	Middle	Upper
None	1500	750	VCT
Lower	2250	1125	VCT
Middle	1125	1125	VCT
Upper	1125	VCT	VCT

When any seal is lost, the differential pressure across the remaining seals increases, and CBO flow increases. An alarm set at 1.25 gpm (normal flow = 1 gpm) will alert the operator to the possibility of a seal failure. Due to the increased flow, controlled bleed off temperature will also increase.

While a controlled bleed off temperature may be caused by a seal failure, loss of CCW to the seal area heat exchanger will also cause an increase in this temperature as well as the inlet temperature to the seal area. The RCP seal area temperature detector senses the outlet temperature of the primary coolant from the lower seal. The temperature detector provides indication and an RCP seal temperature/pressure alarm in the MCR.

The CBO flow from the RCP seals is sent to the VCT in the chemical and volume control system (CVCS). The flow leaving the pump seals is monitored by flow and temperature detectors. The CBO flow detector provides high and low flow alarms in the MCR. A CBO flow temperature detector provides a signal to the plant computer and actuates a high temperature alarm in the MCR.

Each RCP has two proximity probe detectors installed in the shaft coupling area to provide eccentricity and vibration alarms to the MCR.

2.2.7.2 Motor Instrumentation

RCP motor instrumentation includes stator windng temperature, guide bearing temperature, oil reservoir levels, thrust bearing temperature, motor vibration, lube oil cooler temperature and oil lift system instrumentation.

Each RCP has six (6) stator winding temperature detectors. During plant testing, the temperature detector that consistently has the highest temperature indication is selected to provide input into the plant computer. The signal from this temperature transmitter also actuates a high temperature alarm in the MCR.

The upper and lower RCP motor guide bearings each have one temperature detector. Each detector supplies a signal to the plant computer and also actuates a high temperature alarm in the MCR. The RCP pump guide bearing temperature is not monitored by any instrumentation.

The oil level in the upper and lower oil reservoirs of each RCP motor are monitored by two level detectors. Each detector sends a signal to the plant computer and also actuates an oil reservoir low alarm in the MCR.

The upward and downward RCP motor thrust bearings each have one temperature detector. Each detector supplies a signal to indication in the MCR, the plant computer and a thrust bearing high temperature alarm in the MCR.

Each RCP has two vibration switches located on top of the pump motor housing. Each switch supplies an input to the plant computer and actuates a RCP vibration alarm in the MCR. The alarm is common to both switches.

The RCP lube oil cooler has a temperature detector on the cooler oil inlet and outlet lines. The temperature detectors sense the lube oil temperature and send signals to the plant computer. There are no alarms associated with these instruments.

The RCP oil lift system has a local pressure indicator and two pressure switches installed on the oil lift pump discharge header. One pressure switch closes contacts in the RCP breaker permissive circuit to allow closing the breaker. The other pressure switch actuates an oil lift pump low pressure alarm in the MCR.

2.2.8 Reactor Coolant Pump Circuitry

The oil lift pump (OLP) must be in operation at the time of RCP startup and must remain in operation for 30 seconds after RCP startup. The oil lift system uses a separate hydraulic piston pump to lubricate the thrust bearings and upper guide bearings during RCP motor start up. While the RCP is running, the thrust bearing thrust runner acts as the oil pump. The OLP is interlocked with the RCP bus breaker closing circuit so that sufficient oil lift pressure must be available prior to closing the breaker. A timing relay in the RCP bus breaker control circuit automatically secures the OLP after the RCP has been running for 30 seconds.

A device called a synchronizing stick must be inserted into a synchronizing jack at the RCP control section of the main control boards to complete the RCP circuit breaker closing circuit. The synchronizing stick also connects the RCP available power supplies to a synchroscope when used at the electrical distribution control panel so that the RCP bus can be deenergized, or a paralleling operation can be performed with the alternate power supply. The synchronizing stick is normally housed at the electrical distribution control panel.

The last condition that must be satisfied within the control circuitry to start a RCP is sufficient CCW pressure to close a pressure switch contact in the RCP bus breaker closing circuit. The CCW interlock ensures that stator, lube oil and seal cooling are available prior to starting the pump.

2.2.9 Reactor Coolant Pump Operations

2.2.9.1 Normal Operations

Prior to starting any RCP, a steam bubble is formed in the pressurizer and RCS pressure is increased to ~270 psia. This value of pressure will satisfy the minimum recommended pressure for proper seal operation (200 psia) and will ensure that the net positive suction head (NPSH) of 266 psia for a flow rate of 120,000 gpm is satisfied (This flow rate is above the value given in section 2.2.2. 120,000 gpm is the flow rate with only one RCP operating). After pressurizing to the desired pressure, a RCP in each loop is run for 3 to 5 minutes, and the RCS is vented. When venting operations are completed, three (3) of the RCPs are started, and the frictional energy added by the pump impeller (3.3 Mwt/RCP) heats up the RCS.

Because the coolant is very dense when the pumps are first placed in service, each pump will initially require approximately 6000 horsepower. As the coolant temperature increases, pump power requirements decrease to 4500 horsepower at operating temperatures. When coolant temperature increases above 500°F, the fourth pump is placed in service. The 500°F administrative limit is imposed to prevent a high flow rate of dense coolant from lifting fuel assemblies. If the fuel assemblies are lifted, fretting of the fuel element cladding by an adjacent assembly could cause fuel pin clad failure. Above 500°F, the density of the coolant has decreased to a point where full RCS flow will not lift the fuel assemblies.

During power operations, all RCPs are required to be in service providing forced circulation of the reactor coolant. If a RCP trips at power levels greater than 10^{-4} %, a reactor trip will occur on low RCS flow. At power levels of less than 10^{-4} %, the low RCS flow reactor trip may be bypassed.

When the plant is to be shutdown and cooled down, a RCP in each loop is stopped after the reactor is shutdown. This minimizes the heat input into the RCS.

2.2.9.2 Loss of Flow Events

Various loss of coolant flow accidents were analyzed by CE, and the case of the single pump shaft seizure provides the most potential for core damage. While it is definitely possible for a four (4) pump loss of flow incident (due to loss of off site power), it is not considered credible for more than one (1) pump to suffer shaft seizure simultaneously.

With a pump shaft seizure, reactor coolant flow rate drops by nearly 23% within two (2) seconds after initiation. Calculations for this accident indicate that a minimum DNBR of 0.5 will be reached two (2) seconds after shaft seizure. However, conservative estimates indicate that less than two (2) percent of the fuel will actually experience DNBR.

The four (4) pump (loss of off site power) loss of reactor coolant flow accident is actually less severe than the pump seizure because of the availability of the reactor coolant pump motor flywheels to provide coast down flow. By comparison with the pump seizure case, the flow rate for a four (4) pump loss of flow is still greater than 88% of full flow at five (5) seconds after the start of the incident. The minimum DNBR calculated is 1.3 and it occurs just less then three (3) seconds after the start of the incident.

2.2.10 PRA Insights

From a risk standpoint, the RCP seal package is a major contributor. A failure of the seal package may lead to a small break loss of coolant accident which is one of the significant accident sequences listed in the Calvert Cliff's PRA.

Seals fail for many reasons, however, the seal failure probability is increased if CCW is lost. According to NUREG/CR 4948 "Technical Findings Related to Generic Issue 23: Reactor Coolant Pump Seal Failure", when full credit is given for the fourth (vapor seal) stage a negligible core damage frequency is obtained.

2.2.11 Summary

The RCP is a motor driven single stage centrifugal pump that provides forced circulation of reactor coolant. Four (4) pumps, two (2) per loop, are installed in the RCS. Reactor coolant from the steam generators enters the bottom of the pump through the pump suction piping and is pumped to the reactor vessel by the centrifugal force of the impeller. The leakage of coolant along the shaft of the pump is minimized by a seal assembly consisting of three series mechanical seals and a vapor seal.

The RCP motor is a squirrel cage 13.8 kV motor, powered from non-vital ac buses. The motor contains a flywheel that functions to increase flow coast down time and an anti-reverse rotation device that minimizes reverse flow through an idle pump and thereby reduces motor starting current.

TABLE 2.2-2

Reactor Coolant Pump Design Data

Number	4
Type	Vertical, limited leakage, centrifugal
Shaft seals, type, number	Mechanical 4
Materials	
Stationary face	Carbon CCP-72
Rotating face body	ASTM-A-351 Gr. CF8
Rotating face ring	Titanium carbide, kenna-metal K 162-B
Design pressure, psia	2500
Design temperature, °F	650
Normal operating pressure, psia	2250
Normal operating temperature, °F	548
Design flow, gpm	81,200
Total dynamic head, ft.	243
Maximum flow (one pump operation), gpm	120,000
Dry weight, lb.	141,000
Flooded weight, lb.	148,000
Reactor coolant volume, ft^3	112
Motor	
Voltage, Vac	13,800
Frequency, hz./phase	60/3
Horsepower/speed, hot, hp/rpm	4500/900 (nominal)
Horsepower/speed, cold, hp/rpm	6000/900 (nominal)
Service factor	1.15

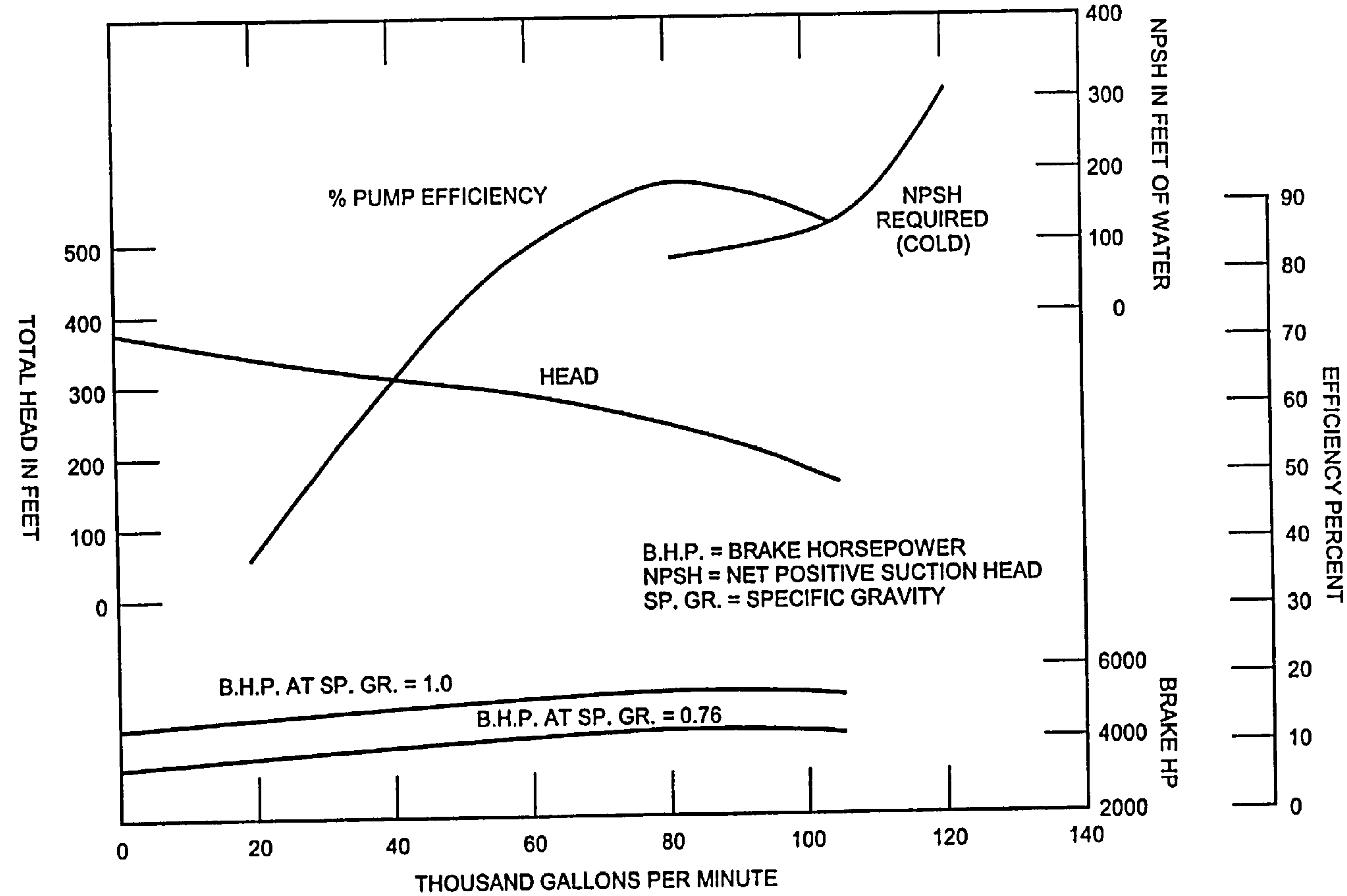

Figure 2.2-1 Reactor Coolant Pump Operating Curve

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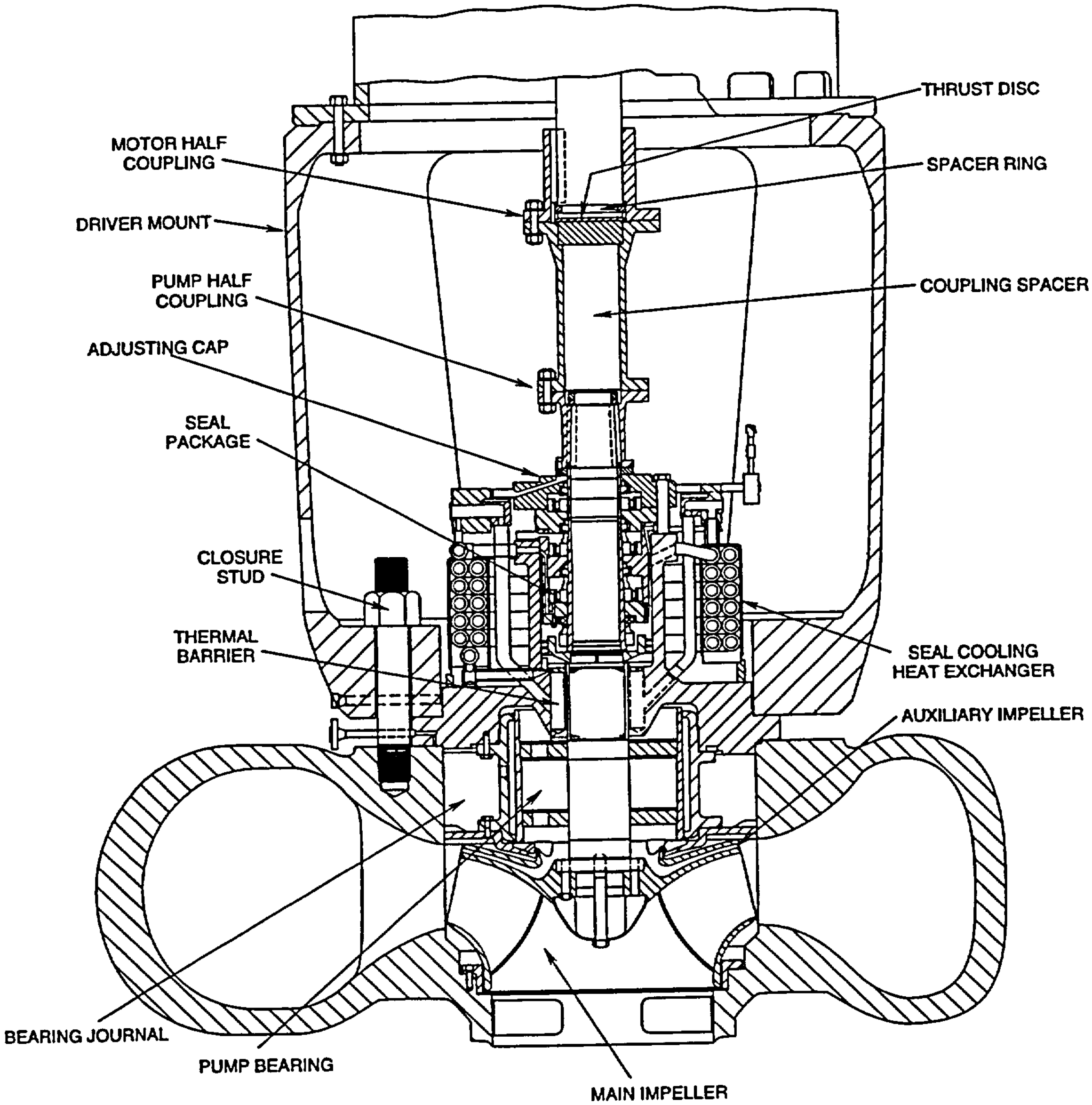

Figure 2.2-2 Reactor Coolant Pump Assembly

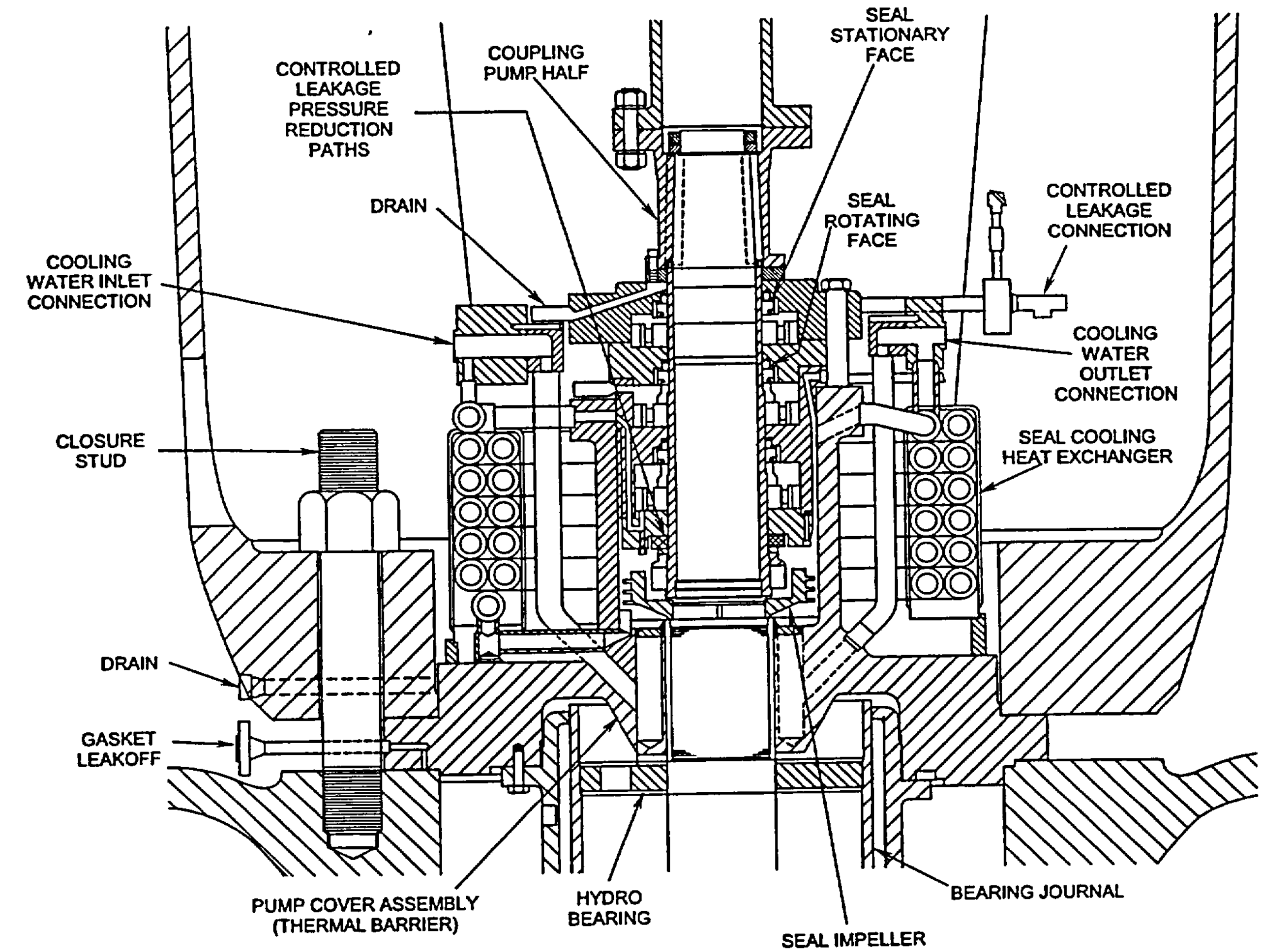

Figure 2.2-3 Reactor Coolant Pump Assembly

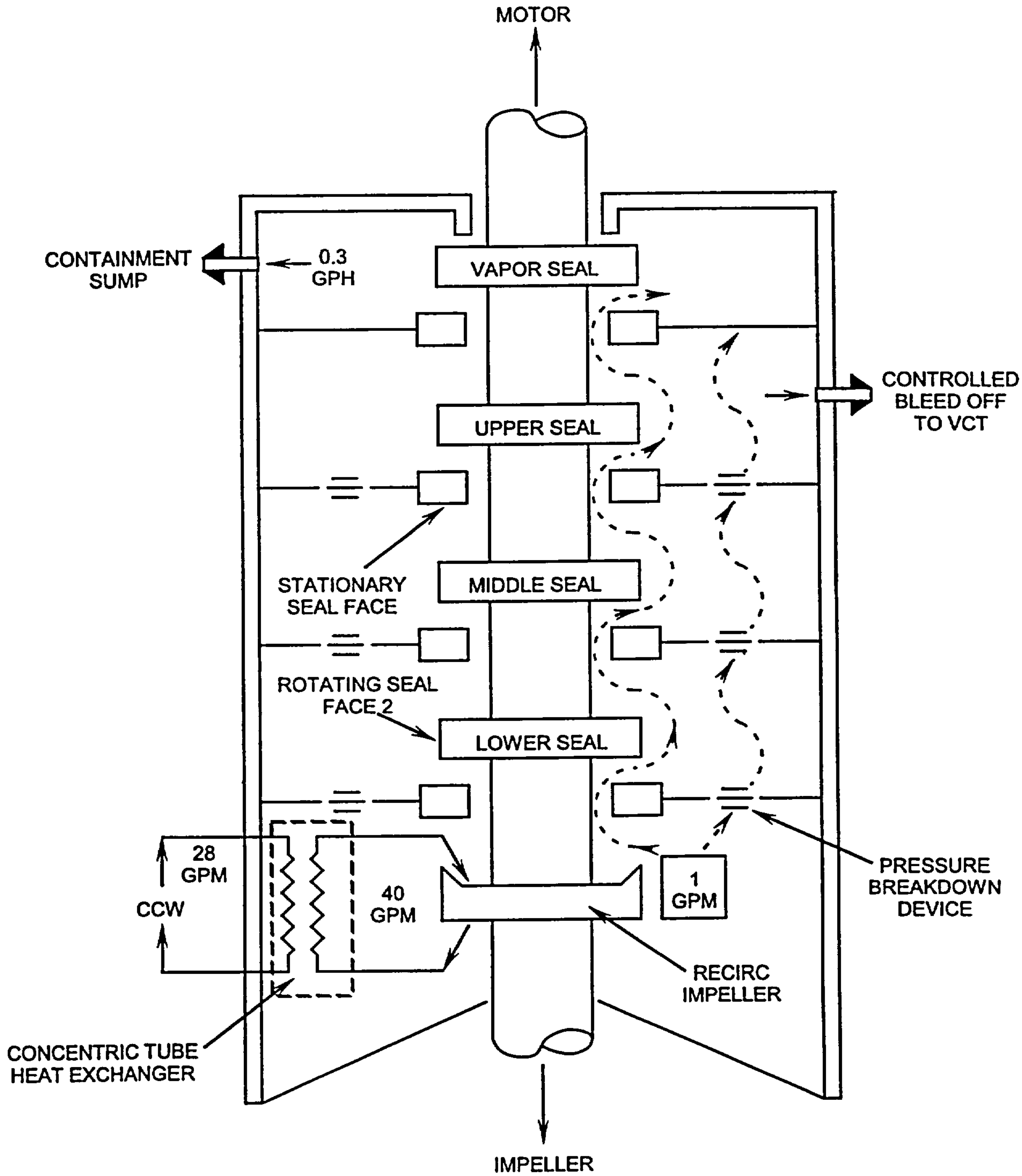

Figure 2.2-4 Simplified Seal Diagram

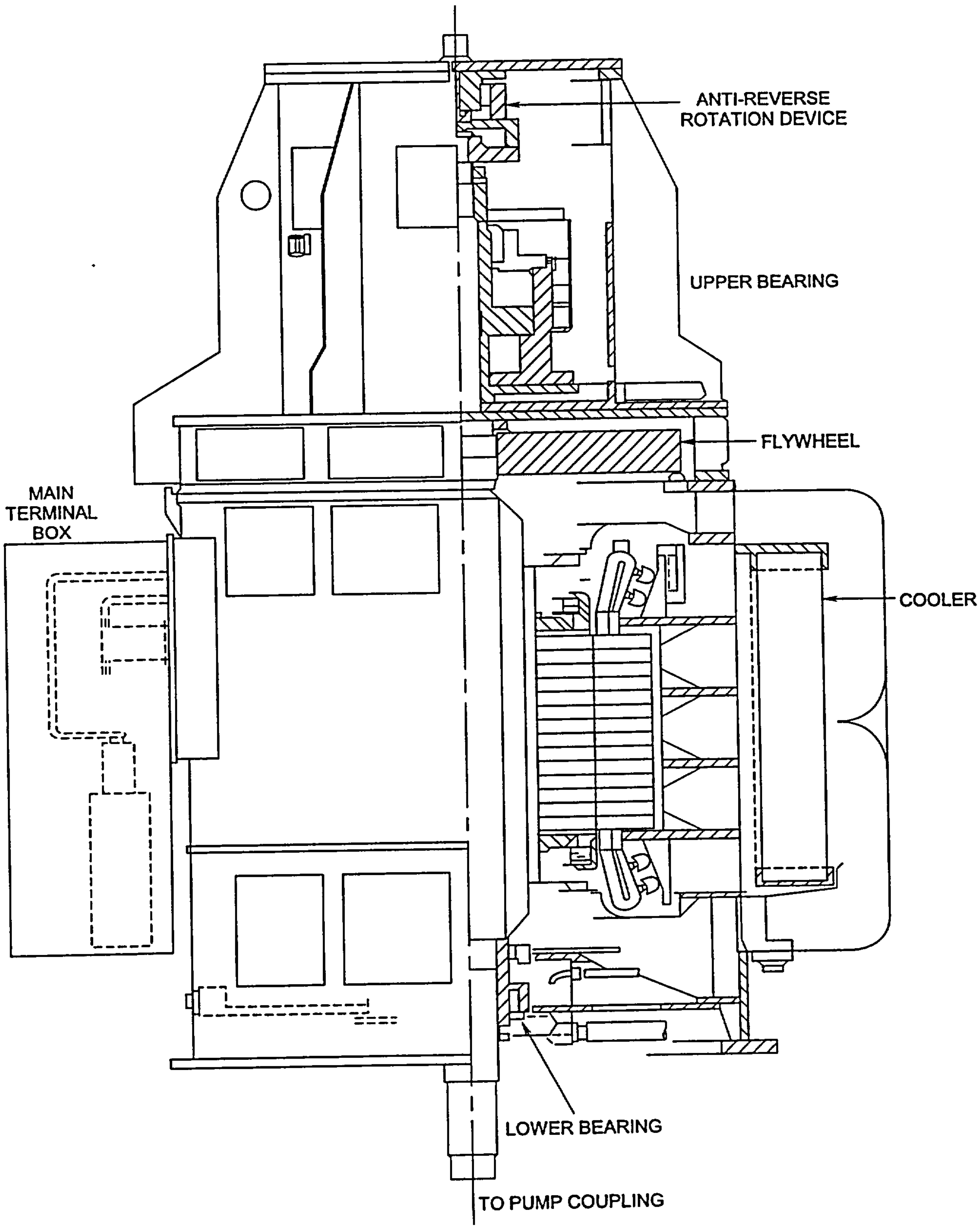

Figure 2.2-5 Reactor Coolant Pump Motor Assembly

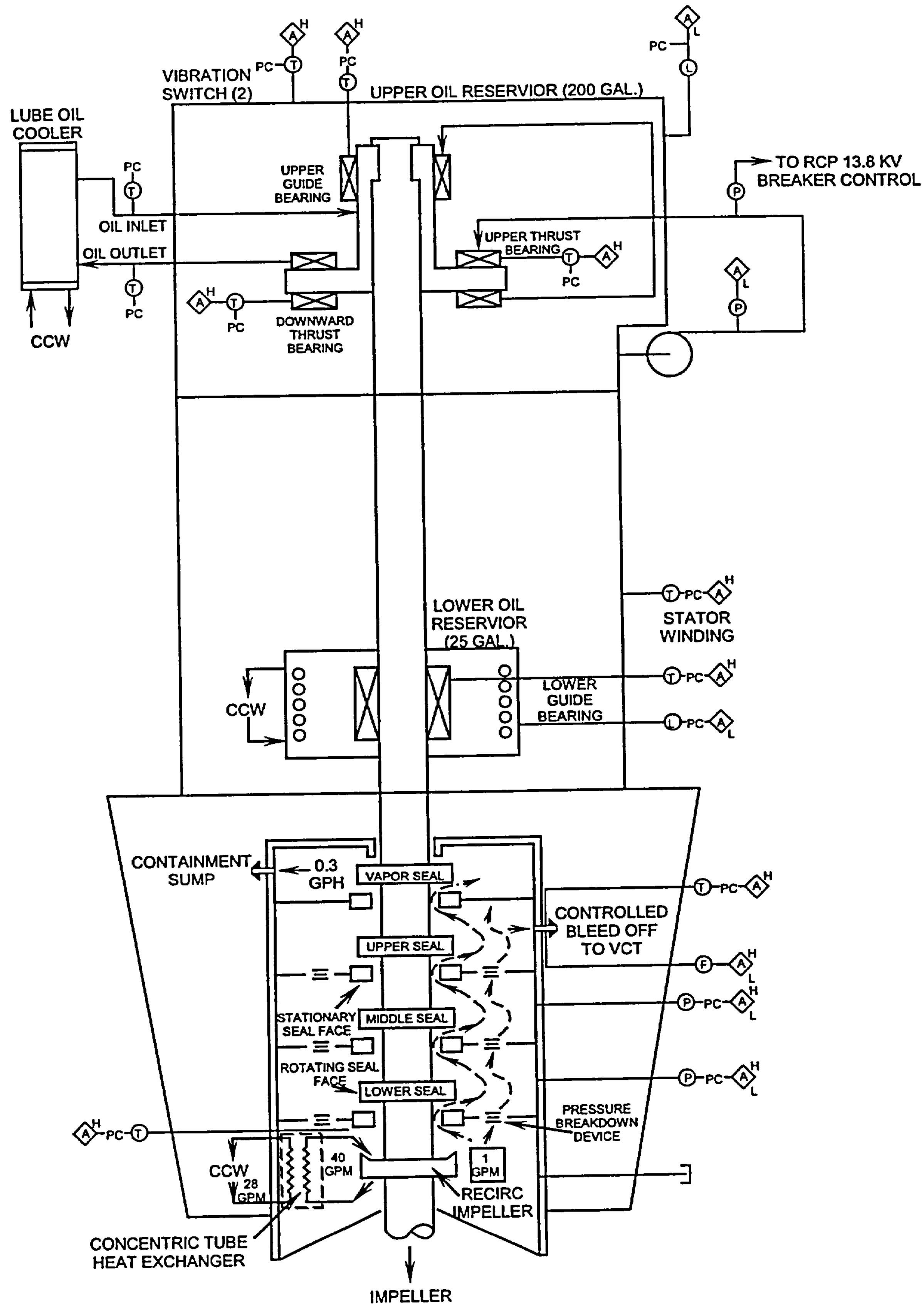

Figure 2.2-6 Reactor Coolant Pump Instrumentation

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2.3 STEAM GENERATORS

Learning Objectives:

1. State the purposes of the steam generators.

2. Describe the primary and secondary flow paths through the steam generators.

3. Explain how dry saturated steam is produced by the steam generators.

4. List the steam generator instrumentation inputs into the reactor protection system (RPS) and the engineered safety features (ESF) systems.

5. List the steam generator instrumentation inputs into the feedwater control system (FWCS).

2.3.1 Introduction

The purposes of the steam generators are:

1. To produce dry saturated steam for the turbine-generator and its auxiliary systems.

2. To act as a heat sink for the RCS during normal, abnormal, and emergency conditions

3. To provide a barrier between the radioactive RCS and the non-radioactive secondary system.

2.3.2 Steam Generator Description

Two (2) identical steam generators are installed in the nuclear steam supply system. Each steam generator is a vertical shell and U-tube heat exchanger and is the heat transfer interface between the RCS and the secondary system. The steam generator vessel is provided with connections to the main feedwater system, the auxiliary feedwater system, the main steam system, the steam generator blowdown system, and steam generator instrumentation. Access to the steam generator internals is provided by two (2) primary and two (2) secondary manways and through two (2) secondary handholes. Each steam generator is supported by a support skirt that is attached to the bottom of the generator.

The primary (RCS) side of the steam generator (Figure 2.3-1) is bounded by the primary head, the bottom of the tube sheet, and the inside of the U-tubes. The primary head is an integral part of the steam generator pressure vessel and is divided into an inlet and outlet plenum by a vertical divider plate. The divider plate separates the reactor coolant inlet (Th) from the reactor coolant outlet (Tc), and directs the flow of coolant through the U-tubes. The steam generator U-tubes (collectively referred to as the tube bundle) provide the primary to secondary heat transfer surface. These tubes are welded to and supported by the tube sheet. The tube sheet is supported by the tube sheet support cylinder.

The secondary side of the steam generator contains feedwater, recirculating water (the water drainage from the steam separators and steam dryers), and steam. The boundaries for the secondary side consist of the upper and lower shell, the top head, the top of the tube sheet, and the outside of the U-tubes. The top head and shell comprise the remainder of the steam generator pressure vessel.

The internal structure of the steam generator secondary side consists of four distinct regions:

1. The downcomer region is the circular area between the tube wrapper and the outer shell of the steam generator from the secondary support plate to the secondary (top) face of the tube sheet.

2. The evaporator region is the area inside of the tube wrapper extending from the secondary face of the tube sheet to the top of the tube bundle.

3. The riser section is the transition area from the evaporator to the steam drum. This area extends from the top of the tube bundle to the bottom of the separator support plate.

4. The steam drum is the area inside the upper shell and top head extending from the bottom of the steam separator support plate to the main steam outlet nozzle.

2.3.3 Steam Generator Flow Paths

There are two distinct steam generator flow paths, one for the flow of reactor coolant and the other for the flow of secondary fluids.

The hot reactor coolant from the reactor outlet enters each steam generator through the inlet nozzle into the inlet plenum of the primary head. The divider plate separates the coolant inlet and outlet such that reactor coolant is directed from the inlet plenum into one end of the vertical U-tubes. As the reactor coolant passes through the tubes, heat is transferred from the coolant, through the tube walls, to the secondary side water. The reactor coolant discharges from the U-tubes into the outlet plenum, and exits the steam generator via two (2) outlet nozzles. The coolant is returned to the reactor vessel by the reactor coolant pumps (RCPs).

During normal operations, feedwater enters the steam generator through the main feedwater nozzle located in the upper portion of the downcomer section. The feedwater flows into the downcomer via the main feed ring. The main feed ring is an annular shaped, horizontal pipe with J-tube extensions. As feedwater discharges from the feed ring, it mixes with and is preheated by the recirculating water from the steam drum. These two sources of water flow downward through the downcomer region, over the tube sheet, and vertically upward into the evaporator region (tube bundle). As the water rises through the tube bundle, heat is transferred from the RCS to the secondary side water. The heat transfer increases the temperature of the water to saturation, adds the latent heat of vaporization, and produces a steam-water mixture with a quality of 30% that flows from the evaporator to the steam drum via the riser section.

The moisture laden steam undergoes a steam water separation process as it passes through the steam separators and dryers in the steam drum. The separators direct the wet steam in a helical motion, causing the more dense saturated liquid to separate from the less dense steam. The water separated from the steam by the steam separators drains onto the separator support plate, and the vapor continues to rise into the steam dryers. These corrugated plates change the direction of the steam flow several times and removes the remaining moisture. The water from the dryers collects on the drain plates, flows down the drain piping to the separator support plate, and mixes with the hot water drainage from the steam separators. The combined steam separator and steam dryer water (recirculating water) returns to the downcomer annulus to mix with the incoming feedwater. The high quality (99.8%) steam leaving the steam dryers rises into the upper dome of the steam drum, flows around the deflector plate, and exits the steam generator via the main steam nozzle.

The flow path of auxiliary feedwater through the secondary side of the steam generator is identical to the main feedwater flow path. Theonly difference is that auxiliary feedwater enters the feedwater line downstream of the feedwater isolation valves.

2.3.4 Detailed Description

2.3.4.1 General Information

The steam generator is a vertical, pressurized-water type, Class A vessel, designed and fabricated in accordance with the American Society of Mechanical Engineers (ASME) Code, Section III. The vessel is constructed of carbon steel and is an integral unit consisting of four sections: the primary head, lower shell, upper shell, and the top head. The steam generator has a dry weight of 1,004,000 pounds and is 749 inches high. The upper shell has an outside diameter of 239 3/4 inches, and the lower shell has an outside diameter of 165 inches.

Reactor coolant enters each steam generator at a flow rate of 61 x 10^6 lbm/hr, a temperature of 599.4°F, and a pressure of 2250 psia. Heat is transferred to the secondary of the steam generator at a rate of 4.386 x10^9 Btu/hr and the reactor coolant exits the steam generator with a temperature of 544.5°F. The pressure drop across the steam generator is 32.08 psi.

2.3.4.2 Primary Side

The primary side of the steam generator is an integral part of the RCS. Boundaries for this side consist of the lower hemispherical (primary) head, the tube sheet, and the U-tubes.

There are several penetrations into the primary head. One (1) 42-inch diameter inlet nozzle and two (2) 30-inch diameter outlet nozzles provide connections to the RCS hot and cold leg piping, respectively. All reactor coolant nozzles are clad with stainless steel for corrosion protection and have carbon steel junctions to provide a means of welding to the RCS piping. The inlet and outlet flows are separated by a stainless steel divider plate.

In addition to the inlet and outlet nozzles, penetrations are made into the lower head for RCS flow instrumentation and the two (2) primary manways. Four (4) instrument nozzles penetrate the outlet side of the primary head and provide the low pressure input to the RCS flow differential pressure detectors. Two (2) 16-inch diameter primary manways are provided in the primary head for inspection and maintenance. The manways are closed externally (with 20 studs and nuts) by a manway cover sealed with a stainless steel gasket retainer plate and a spiral wound gasket.

The tube sheet is welded to the primary head and the lower shell along its circumference and is reinforced by the forged tube sheet support cylinder between the center of the tube sheet and the primary head. The tube sheet is a flat disc forging 21 1/2 inches thick and clad with Ni-Cr-Fe alloy (Inconel) on the reactor coolant side.

The tube sheet separates reactor coolant from the secondary side, and contains penetrations for the steam generator U-tubes.

The 8,519, vertical, 3/4 inch O.D., U-tubes have an average wall thickness of 0.048 inches and are constructed of inconel. Since these tubes form the primary to secondary boundary, Inconel is chosen for increased tube integrity. Inconel has a high resistance to general corrosion and is not susceptible to chloride stress corrosion. The tubes are explosively expanded into the tube sheet and are welded to the tube sheet top to prevent bypass flow of RCS fluid into the secondary side. The tubes are supported against lateral vibrations by steel egg crates (Figure 2.3-2) at intervals of three (3) feet or less along their entire length. The egg crate design minimizes crevices and low flow areas that would allow the concentration of solid impurities in the steam generator. The top of the tube bundle is supported by a bat wing support assembly (Figures 2.3-3 and 2.3-4) that is designed to minimize the flow resistance encountered by the steam/water mixture.

2.3.4.3 Secondary Side

The secondary side of the steam generator is bounded by the upper and lower shell, the top head, and the secondary side of the tube sheet and the U-tubes. Secondary side connections are provided in the shell for main feedwater, auxiliary feedwater, surface and bottom blowdown, and steam generator instrumentation. A connection for main steam is provided at the top of the steam drum. Access to the steam generator steam drum is provided by two (2) 16 inch diameter gasketed manways. Each manway cover seats internally and swings into the steam drum on a hinged rod. The lower shell is provided with two (2) six (6) inch diameter gasketed handholes for inspection of the tube bundle.

During normal operations, the secondary side flow path receives preheated, chemically treated feedwater from the main feedwater system. The feedwater enters the steam generator through the 18 inch diameter main feedwater nozzle located on the upper shell at the top of the downcomer section (Figure 2.3-1). At full power, feedwater enters the generator with a temperature of 432°F. After entering the steam generator, the feedwater is distributed evenly around the periphery of the downcomer through the main feed ring. The main feed ring is a donut-shaped (torus shaped), 12 inch diameter steel pipe that encircles all but three (3) feet of the downcomer annulus. The break in the piping is provided for maintenance access. Each end of the feed ring is capped. To prevent the quick drainage of the feed ring after a loss of feedwater flow, and the subsequent possibility of water hammer, J-tubes (Figure 2.3-5), mounted on the upper portion of the feed ring, provide the discharge path from the feed ring. Feedwater flows out the J-tubes and falls downward into the downcomer region.

Supply from the auxiliary feedwater system enters the steam generator through the main feedwater nozzle. After entering the steam generator, the auxiliary feedwater is distributed through the main feed ring.

The feedwater discharging from the feed ring mixes with, and is preheated by, the hot drainage (recirculating water) from the steam drum. The secondary side water in the downcomer region travels downward over the inside wall of the steam generator vessel shell and over the outside wall of the tube wrapper. The tube wrapper is a steel cylinder that fully encloses the tube bundle, separating the downcomer and evaporator regions.

At the bottom of the downcomer region, the secondary side water flows inward over the secondary face of the tube sheet and upward around the U-tubes. As the water rises over the surface of the tubes in the tube bundle (evaporator region), the heat transfer from the RCS increases the temperature of the water to saturation temperature and adds the latent heat of vaporization. The steam/water mixture that is formed continues to rise from the evaporator to the steam drum via the riser.

During full power operations, the saturated water to wet steam interface exists in the riser section at a location approximately two (2) feet below the steam separator support plate, The moisture-laden steam rising from the normal steam generator water level enters the steam drum where it undergoes a steam/water separation process, The large moisture content of the steam is removed by 166 steam separators and 126 steam dryers. The moisture separating equipment precludes moisture carryover and excessive condensation in the main steam piping, and resultant damage to the turbine.

The wet steam begins the steam/water separation process by first entering the steam separators through the bottom of the steam separator support plate. The steam separators (Figure 2.3-6) are perforated cylinders equipped with vanes in their lower section. As the wet steam enters the separators, the vanes force the steam/water mixture into a circular motion. The circular motion of the steam/water mixture separates the steam from the water by forcing the denser water to the walls of the cylinder. The water collects on the walls of the cylinder and drains through the holes in the separator to a sump in the center of the steam separator support plate, The hot water then flows from the separator support plate sump to the downcomer via the recirculating water sump drain tube. The bulk of the moisture in the steam is removed by the steam separators.

The separated steam exits the separator through the top center hole and flows upward to the steam dryers. The steam dryers (Figure 2.3-7) are corrugated metal baffle plates which provide a tortuous path for steam flow. The moisture impinges on the baffle sides and drops to the drain plate just below the dryers. This hot drainage flows down 32 steam dryer drains to the separator support plate and mixes with the water from the steam separators.

The 99.8% quality steam rises into the upper dome of the steam drum and flows around the steam deflector into the 34 inch ID main steam outlet nozzle. At full power, the saturated steam exits the steam generator at a rate of 5.635 X 10^6 lbm/hr, a pressure of 850 psia and a temperature of 525.2°F.

2.3.4.4 Steam Generator Design Transients

The design of each steam generator is based on consideration of the heat exchange capacity, temperatures and volumetric flow rates of the reactor coolant and feedwater, and the allowable pressures in each flow path. Data on limiting values and design criteria are derived from operating experience and laboratory investigations.

Each steam generator is designed to withstand the following reactor plant cyclic transients:

1. 500 heatup and cooldown cycles during the 40 year design life at rates of 100°F/hr between 70°F and 532°F.
2. 15,000 power change cycles over the range of 15% to 100% of full load with a ramp load change of 5%/minute.
3. 2,000 cycles of 10% full load step changes, increasing from 10% to 90% of full power and decreasing from 100% to 20% of full load.
4. Ten (10) cycles of hydrostatic testing of the RCS at 3125 psia and a temperature of at least 60°F above the nil ductility transition temperature (NDTT) of the component having the highest NDTT.
5. 320 cycles of leak testing at 2500 psia and at a temperature at least 60°F above the nil ductility transition temperature (NDTT) of the component having the highest NDTT.
6. 106 cycles of normal variations of 100 psi and 6°F at operating temperatures and pressures.
7. 400 reactor trips from 100%.

These design cyclic transients include conservative estimates of the steam generator operational requirements. The following abnormal transients were also considered when arriving at a satisfactory usage factor as defined in Section III of the ASME Boiler and Pressure Vessel Code:

1. 40 cycles of loss of turbine load from 100% power without a direct reactor trip.
2. 40 cycles of total loss of RCS flow at 100% power.
3. Five (5) cycles of loss of secondary system pressure.

In addition to all of the cyclic transients listed above, each steam generator is also designed to withstand the following conditions such that no component is stressed beyond the allowable limit as described in the ASME Code, Section III:

1. 4,000 cycles of transient pressure differentials of 85 psi across the primary head divider plate due to starting and stopping of RCPs.

2. Ten (10) cycles of secondary hydrostatic testing from zero (0) psia to 1250 psia.

3. 320 cycles of secondary side leak testing from zero (0) psia to 1000 psia.

4. 5,000 cycles of adding 600 gpm of 70°F feedwater with the plant in hot standby.

In addition to all of the normal design transients, an abnormal transient initiated by eight (8) cycles of adding a maximum of 650 gpm of 70 °F feedwater with the steam generator dry and at 600°F was also considered at arriving at a satisfactory usage factor for the steam generators.

2.3.5 Operating Characteristics

2.3.5.1 Heat Transfer

The rate of heat transfer, Q, from the primary side to the secondary side is determined by:

1. The temperature differential between the average reactor coolant temperature (Tavg) and the saturation temperature (Tsat) of the steam generator.

2. The heat transfer surface area (A) of the U-tubes; and

3. The overall heat transfer coefficient (U), which is dependent upon the nature of the tube's material, the material's geometry, and the convection film coefficient of the tube's inner and outer surfaces.

The mathematical relationship representing the heat transfer from the primary side to the secondary side of the steam generator is:

$$Q = UA(T_{avg} - T_{sat})$$

As can be seen from this equation, the rate of heat transfer is directly proportional to the differential temperature, the heat transfer surface area, and the heat transfer coefficient. The later two variables are constants for all practical purposes. As steam flow from the steam generators is increased, the heat removal from the steam generators is increased. The increased heat removal rate results in a larger differential temperature and a lower Tsat. When steam temperature is decreased, steam pressure drops and turbine efficiency is adversely affected. Therefore, as power is increased, Tavg is ramped from 532°F to 572.5°F to minimize the decrease in steam pressure. Figure 2.3-8 plots RCS temperatures and steam generator pressure versus power.

2.3.5.2 Shrink and Swell

During power operations, the water level in the steam generators varies during periods of transient operation. These phenomena are known as shrink and swell and occur when the pressure/temperature equilibrium, which normally exists between the vapor and liquid in the steam generators during steady state operations, is perturbed.

Before swell can be discussed, it should be noted that there are two sources of water to the steam generator's downcomer region. One source is from the main feedwater system, the other source is the internally recirculating water from the steam separators and the steam dryers. An adequate flow of secondary water (feedwater combined with recirculating water) and of the steam/water mixture is required for satisfactory steam generation and for the preheating of feedwater.

The necessary flow is produced by the density difference between the secondary water in the downcomer and the steam/water mixture in the evaporator. The secondary water entering the downcomer is comparatively cool and dense, causing a downward pressure under the force of gravity. As this secondary water passes over the tubes, it is heated and forms a steam/water mixture. In forming this mixture, the density of the fluid is decreased. Since the heated water weighs less, the force (pressure) imbalance (between the fluids in the downcomer and the evaporator) results in a natural circulation flow of water in the secondary side of the steam generator from the downcomer into the evaporator section.

The term swell refers to the increase in steam generator level which is experienced when there is an increase in steam flow caused by the opening of the turbine control valves or the steam dump and bypass valves. When the increase in steam flow exceeds the steam generator's ability to supply the steam at the required rate and results in a decrease in steam generator pressure. With this steam generator pressure decrease, the steam bubbles within the evaporator section grow larger in size, and more hot water flashes to steam. Also, as the saturation pressure of the steam generator decreases, the saturation temperature decreases causing a greater temperature differential from the primary to the secondary side of the steam generator. Increased heat transfer from the RCS to the secondary water creates additional steam bubbles to accommodate the load increase. Overall, the volumetric expansion of the steam/water mixture in the evaporator/riser section of the steam generator results in increased resistance to flow across the evaporator and riser sections. This results in a rise (swell) in the downcomer region. Steam generator level is measured in the downcomer region, and level increases. The increased downcomer water level will increase the steam generator natural circulation until a new equilibrium is established.

During decreases in steam flow rates, the reverse phenomenon, known as shrink occurs. Decreases in steam flow result in increases in steam generator pressure. The steam bubbles in the steam generator collapse, and the volume of the steam-water mixture in the evaporator/riser regions decreases. This results in a decreased resistance to flow across the U-tubes and a subsequent decrease in steam generator downcomer level. Again, level is measured in the steam generator and there is a decrease (shrink) in steam generator level.

2.3.5.3 Recirculation Ratio

The quanity of water returned to the downcomer annulus from the moisture separating equipment is several times greater than the quantity of incoming feedwater. The circulation of secondary water is important to steam generator operations for two reasons:

1. If circulation is inadequate, the heat transfer surfaces tend to become blanketed with steam rather than continuously wetted by a steam/water mixture. This significantly reduces the heat transfer of the steam generators.

2. Circulation preheats the incoming feedwater thus reducing the temperature difference between the relatively cold feedwater and the hot tube sheet and the U-tubes. Preheating the feedwater minimizes the thermal stresses on these components and thus maintains their integrity.

An index of the amount of steam generator internal mixing is provided by the ratio called the circulation ratio (C). This ratio is defined as the amount of flow in the downcomer divided by the amount of exit steam flow:

$$C = \frac{\text{downcomer flow}}{\text{exit steam flow}}$$

Because the water is continually returned through the internal recirculation flow path from the moisture separating equipment, the index of internal mixing is also referred to as the recirculation ratio (Cr). The recirculation ratio is defined as the amount of flow in the riser divided by the exit steam flow:

$$Cr = \frac{\text{riser flow}}{\text{exit steam flow}}$$

The circulation ratio and recirculation ratio are both an index to internal mixing, and since the riser flow is equivalent to downcomer flow, they are numerically equal.

The balance reached between the force of the weight difference of the downcomer water and the riser steam/water mixture, and the friction (head loss) that results from the water flow (through the downcomer, tube bundle, riser, and steam separators and dryers) determines the circulation flow rate. As power increases, the circulation flow rate, and consequently the recirculation ratio is affected by two factors:

1. The change in the rate of heat transfer, and

2. The change in steam generator pressure.

As power increases, the rate of heat transfer increases and more steam is produced in the evaporator section. This causes the density and, therefore, the weight of the steam/water mixture in the riser section to decrease providing an increased driving head (density difference) for circulation flow. However, resistance to this increased flow increases at an even faster rate. This is because the head loss is directly proportional to the velocity of the flow squared. The countering effect of the increased head loss causes the circulation flow rate to quickly level off after an increase in reactor power.

The affect of the steam generator pressure change from an increase in power on the circulation flow rate is similar. When steam demand increases, more steam is formed per unit time. This decreases the time of contact for the feedwater with the hot U-tubes and requires an increased supply of cold feedwater. These factors decrease the average temperature of the secondary side. Since the steam generator produces saturated steam, a decrease in the steam temperature results in a decrease in the steam generator pressure. This pressure decrease has the same affect as the density decrease caused by the increase in heat transfer.

Together, the changes in steam generator pressure and in heat transfer rate from an increase in power effect the circulation flow rate. At low power levels, increasing power causes an increase in circulation flow rate, while at relatively high power levels (50% or greater) the circulation flow remains relatively constant due to the overriding effect of the increased resistance to flow. Since the steam flow rate increases for an increase in power, and the circulation flow rate is relatively constant at high power levels, the recirculation ratio decreases from its maximum value of 33:1 at 5% to a low of 4:1 at 100% power.

2.3.6 Steam Generator Chemistry Control

The water on the primary and secondary side of the steam generator is chemically treated to ensure equipment integrity. Improper chemistry control will cause cracks and pits in steam generator U-tubes, general surface corrosion, moisture carryover, and fouling of heat transfer surfaces. To maintain the integrity of the steam generator, RCS and secondary water chemistry specifications must be observed at all times.

The secondary chemistry specifications ensure that secondary chemistry is maintained through the control of five factors: pH, oxygen, chlorides, conductivity, and solids. The importance of each of these factors will be discussed in the following sections. The specifications for these parameters is listed in Table 2.3-1

2.3.6.1 pH Control

In water, iron and steel undergo corrosion by an electrochemical process. In a depleted oxygen environment and at high temperatures, iron reacts with water to form a protective film of magnetite (Fe_3O_4). This protective film protects the piping from further corrosion. One of the variables that influences the corrosion rate of iron and steel is the pH of the water. A high concentration of H+ ions in acidic solutions prevents the formation of the protective magnetite film. Studies have shown that the corrosion of steel and iron is minimized (the magnetite film is maintained) in relatively high pH environments. pH is controlled in the steam generators by the addition of ammonium hydroxide to the condensate system.

2.3.6.2 Oxygen Control

The presence of oxygen in the steam generator results in the formation of a non-protective ferric iron hydroxide. Once formed this corrosion product converts to magnetite very slowly, and the development of a protective film is impeded. Oxygen control also minimizes pitting and chloride stress corrosion.

Oxygen is controlled by the deaerating feature of the condenser and by the addition of hydrazine to the condensate system. If oxygen is maintained at low levels in the condensate and feedwater systems, the oxygen content in the steam generators will also be at a low level. An oxygen specification is not listed in Table 2.3-1 because there is a 10 ppb limit placed on condensate system oxygen.

TABLE 2.3-1 SG CHEMISTRY LIMITS

Parameter	Value	Units
pH	9.2-9.5	N/A
Specific Conductivity	4	mhos/cm
Cation Conductivity	0.8	mhos/cm
Sodium	20 (max)	ppb
Chlorides	80(max)	ppb
Silica	300(max)	ppb
Suspended Solids	1000	ppb

2.3.6.3 Conductivity and Chlorides

The elimination of impurities such as calcium, magnesium, and sodium ions in the steam generator secondary water is necessary to prevent the formation of hard scale on the U-tubes. The elimination of sodium also reduces stress and pitting corrosion. Conductivity is measured to monitor the concentration of these ions. The most likely source of these ions is condenser tube leakage.

In-leakage from the condenser will also introduce chlorides into the steam generators. Concentrations of chlorides can lead to chloride stress corrosion and rapid U-tube pitting.

Two methods are employed to control impurity ingress into the steam generators. The first method involves the use of condensate demineralizers (ion exchangers) that purify the condensate system. The second method is steam generator blowdown which is discussed in a later section of this chapter.

2.3.6.4 Solids Control

Although formation of a soft sludge in the steam generators is preferable to that of a hard scale, the soft sludge (along with other dissolved and suspended solids) will contribute to increased corrosion and a reduction in heat transfer capabilities. Chlorides will concentrate in the sludge deposits on the tube sheet, tube support plates, and exposed U-tube surfaces, and promote rapid tube pitting and subsequent damage to the steam generator tubes. Additionally, deposits surrounding the U-tubes will inhibit proper heat transfer from the RCS. Soft sludge deposits in the steam generator are controlled by steam generator blowdown and by the filtration of impurities by the condensate demineralizers.

Silica is a deposit that is specifically measured and controlled because it may enter the steam generator in the form of a soluble compound that is not efficiently removed by the condensate demineralizers. Silica readily dissolves in alkaline water and will react with calcium and/or magnesium ions in the water to form an extremely adherent scale. Silica is also soluble in steam, with a rapidly increasing solubility above 500°F. A high concentration of silica in the steam generator can cause the transportation of this impurity into the turbine. Subsequent deposition of silica on the turbine blades results in a loss of turbine efficiency.

2.3.7 Steam Generator Blowdown and Recovery System

The steam generator blowdown and recovery system provides the following functions:

1. Maintains steam generator water chemistry limits by continuous removal of impurities through the steam generator blowdown connections.

2. Provides an indication of primary to secondary leakage by sampling the blowdown for radioactivity.

3. Minimizes the loss of secondary inventory by purifying the steam generator blowdown and returning it to the condenser hotwell.

The steam generator blowdown and recovery system is connected to each steam generator at the bottom and surface blowdown connections. The two (2) inch diameter bottom blowdown nozzle is internally connected to a blowdown ring mounted on the tube sheet in the area of the domed head of the tube sheet support cylinder. The one (1) inch diameter surface blowdown nozzle is internally connected to a header that is located above the main feed ring. Separate blowdown lines connect to each nozzle and pass through the containment wall where they join into a common line. A pneumatically operated containment isolation valve is located in each surface and bottom blowdown line just after it penetrates the containment wall. These isolation valves shut automatically upon generation of a high radioactivity alarm by the Radiation Monitoring System (RMS).

The blowdown lines are connected just downstream of the containment isolation valves and the piping is routed to a 2,350 gallon blowdown tank. A manual throttle valve is located in the common line between the isolation valves and the blowdown tank. The valve is positioned to provide the desired steam generator blowdown rate (normally 150 gpm).

During normal operations, blowdown flows from both steam generator bottom blowdown connections to the blowdown tank. This continuous blowdown helps to maintain steam generator chemistry and provides water for radioactivity sampling. Primary to secondary leak detection is conducted continuously by the blowdown radiation detection flow path. This flow path consists of a pump, a cooler, and a radiation detector. A small portion of the blowdown tank's contents (0.3 gpm) is routed through the cooler, the radiation monitor, and is returned to the blowdown tank by the pump.

The majority of the blowdown tank's contents is returned to the condenser. Blowdown tank pressure provides the driving head for flow through the system. During normal operations, the flow from the tank is routed through coolers that reduce the temperature to a value that is compatible with ion exchanger operation (~120 °F). One of the coolers is cooled by the condensate system, and the second cooler is cooled by the service water system. From the coolers, the blowdown passes through filters and ion exchangers that remove insoluble and soluble impurities respectively. The outlet of the ion exchangers normally discharges to the condenser. The outlet of the ion exchangers can also be routed to the circulating water system or to the miscellaneous waste system (MWS). The circulating water discharge would be used during steam generator draining activities, and the MWS connection is automatically placed in service if a high radiation level is sensed on the outlet of the ion exchangers.

2.3.8 Steam Generator Instrumentation

The operation of each steam generator is monitored by secondary side water level, secondary side steam pressure, and reactor coolant flow instrumentation. These instruments provide safety-related signals to the reactor protection system (RPS) and engineered safety features (ESF) system, and inputs to non-safety related secondary protection and control systems. Each of the instrumentation systems will be discussed in subsequent paragraphs.

2.3.8.1 Steam Generator Level

Ten (10) level transmitters monitor steam generator secondary side level. Six (6) of these transmitters are narrow range, and four (4) of the transmitters are wide range. The narrow range level indication has a range of 183.16 inches and is calibrated from 0 to 100% of this range. The upper narrow range level tap is located in the steam drum section, 614 5/16 inches from the base of the steam generator. The lower narrow range level tap is located in the downcomer region, 431 5/32 inches from the steam generator base. The upper wide range level tap is located at the same elevation as the upper narrow range level taps, and the lower wide range level tap is located at the steam generator tube sheet. The wide range level indication has a range of 486 inches.

Four (4) of the narrow range level transmitters supply the RPS. The RPS generates a low steam generator level (37%) trip to ensure that the steam generator's heat sink availability is maintained. The RPS employs a two (2) out of four (4) logic system; therefore, at least two (2) transmitters must sense the low level condition. In addition, these narrow range level transmitters provide an input to the turbine trip system. If the steam generator level reaches a predetermined high level (92.5%), the turbine is tripped. High steam generator levels can lead to moisture carryover into the main steam system which can lead to turbine damage. Two (2) out of four (4) logic is also used to generate the turbine trip.

The remaining two (2) level transmitters supply a signal for steam generator level control. During normal operations, steam generator level is controlled at 65% by the feedwater control system. These transmitters are not safety related.

The four (4) wide range level transmitters are used to actuate the auxiliary feedwater system (AFW). If two (2) out of the four (4) wide range level transmitters sense that level has dropped to a level of 40%, an automatic start signal will be sent to the AFW system. The AFW system is a subset of the engineered safety features system.

2.3.8.2 Steam Generator Pressure

Four (4) safety related steam generator pressure transmitters are installed on each steam generator. The pressure transmitters are connected to the upper level transmitter connections. The pressure transmitters supply signals to the ESF and the RPS systems. The ESF system generates a steam generator isolation signal (SGIS) if steam generator pressure drops to 703 psia. The SGIS signal will close the main steam isolation valves, the main feedwater isolation valves, and will trip the main feedwater pumps, the condensate booster pumps and the heater drain pumps. The RPS will generate a reactor trip at the same setpoint. The purpose of the reactor trip is to protect the core from a reactivity addition accident in the event of a steam line break. Both the ESF and RPS use a two (2) out of four (4) logic to generate actuation signals.

The steam generator pressure signals are also used in the asymmetrical steam generator transient circuit. This circuit compares each steam generator pressure and provides a signal to the thermal margin low pressure (TMLP) RPS trip circuitry. The purpose of this circuit is to prevent large radial flux distributions in the event that a main steam isolation valve is closed at power.

2.3.8.3 RCS Flow

Eight (8) independent differential pressure detectors (four (4) per loop) tap into the hot leg and into the steam generator outlet plenum. The outputs of the differential pressure transmitters are summed, by pairs, and four (4) total RCS flow signals are sent to the RPS. The RPS generates a low RCS flow trip at 95% if low flow conditions are sensed by two (2) out of the four (4) transmitters.

2.3.9 Steam Generator Operations

2.3.9.1 Plant Startup

When the plant is in a cold shutdown condition, the steam generators are in a wet layup condition. Wet layup consists of filling the steam generator completely with water that has been treated with hydrazine and ammonium hydroxide. The high steam generator level minimizes the amount of secondary metal that exposed to air during cold shutdown. Wet layup levels are monitored on the wide range level indication.

Since the steam generators are full, the generators must be drained down to the normal operating level (65%) prior to startup. Also, condensate and feedwater must be cleaned up prior to using these systems to feed the steam generators. These two steps are started early in the plant startup procedure.

As the RCS is heated up by the RCP energy, steam production begins in the steam generators. The level in the steam generators will be maintained by AFW. When hot standby conditions are achieved, the necessary RCS boron concentration adjustments are made and the control element assemblies are withdrawn to achieve criticality. Reactor power is escalated to approximately 3%, and a main feedwater pump is placed in service. When feedwater control via the main feedwater system is established AFW is aligned to its standby lineup. During power operations, the steam generator functions to produce dry saturated steam to drive the turbine and required plant auxiliaries.

2.3.9.2 Plant Shutdown and Cooldown

To shut the unit down, plant power is decreased by boration of the RCS. When power is approximately 10%, the turbine is taken off line. At 3% power AFW is placed in service and the main feedwater pump is shut down. The next step is to shut down the reactor by inserting the control element assemblies. When the control element assemblies are inserted, the plant is in the hot standby mode of operation. The cool down of the plant is performed in two steps. The first step involves dumping steam from the steam generator to the condenser (steam may be dumped to the atmosphere if the condenser is not available), AFW is used to maintain steam generator level.

When RCS temperature and pressure are reduced to approximately 300°F and at or less than 260 psia, the shutdown cooling system is placed in service and is used to cool the plant down to the desired temperatures. In the meantime, the steam generators will be placed in wet layup by using AFW.

2.3.9.3 Natural Circulation

Natural circulation refers to the deposition of the core's decay heat energy into the steam generator and is caused by coolant density and elevation differences. Natural circulation provides a means of controlled core cooling using the steam generators if the reactor coolant pumps are not available.

Three conditions must exist for natural circulation. First, there must be a heat source. The decay heat generated after a plant shutdown or trip provides the heat source. Next, a heat sink for the deposition of the core heat must exist. The steam generators will satisfy this requirement providing, a level is maintained in the steam generators and a temperature difference is maintained between the RCS and steam generators by the removal of steam from the secondary side. Finally, an elevation difference must exist between the heat sink and heat source. Plant design provides an elevation difference of approximately thirty five feet between the centerline of the steam generator and the centerline of the core. Of course, the interconnecting piping from the reactor vessel to the steam generators must be intact and free from obstructions such as non-condensable gasses.

If the above conditions are satisfied, one possible natural circulation scenario might include a loss of offsite power. When this event occurs, the electrical power supply to the reactor coolant pumps is lost, and they coast down to zero (0) rpm. With no forced flow, the coolant in the core begins to heat up. The increase in coolant temperature causes a reduction in coolant density. As the hot coolant rises, it is replaced with colder, denser water from the steam generators. When the hot water from the core reaches the steam generators, its temperature is reduced and its density increases. The denser water travels back to the core where the process starts all over.

2.3.10 Summary

The steam generators are inverted U-tube heat exchangers that are used to remove the core's heat energy during normal and abnormal operations. During normal operations, the steam produced by the transfer of heat from the RCS is used to drive the turbine and its auxiliaries.

During abnormal operations, the removal of steam from the steam generator ensures the removal of decay heat.

The heat transport path of reactor coolant consists of the hot leg inlet that routes the fluid to the inlet of the U-tubes. The reactor coolant

passes through the tubes which provide a barrier between the radioactive reactor coolant and the non-radioactive secondary fluid.

From the U-tubes, the coolant travels to the suction of the reactor coolant pumps via two (2) outlet nozzles.

Feedwater enters the steam generator shell and is distributed to the downcomer by the feed ring. The feedwater comes in contact with the tubes in the evaporator section of the steam generator and is boiled. Wet saturated steam is dried by two stages of moisture separating equipment prior to its entry into the main steam system.

Safety related instrumentation monitors steam generator levels, steam generator pressures, and RCS flow. Levels are used to generate reactor and turbine trips and to actuate AFW.

TABLE 2.3-1

Steam Generator Parameters

Number, per unit	2
Type	Vertical U-Tube
Number of tubes	8519
Nozzles and manways	
Primary inlet nozzle (1 ea.), ID, in.	42
Primary outlet nozzle (2 ea.), ID. in.	30
Steam nozle (2 ea.), ID, in.	34
Feedwater nozzle (1 ea.), nominal, in.	18
Instrument taps (12 ea.), nominal, in.	1
Primary manways (2 ea.), ID, in.	16
Secondary manways (2 ea.), ID, in.	16
Secondary handholes (2 ea.), ID, in.	6
Bottom blowdown (1 ea.), nominal, in.	2
Surface blowdown (1 ea.), nominal, in.	1
Auxiliary feedwater (1 ea.), nominal, in.	4
Primary side design	
Design pressure, psia	2500
Design temperature, °F	650
Design thermal power (NSSS), Mwt	2700
Coolant flow (ea.), lbm/hr	61E6
Normal operating pressure, psia	2250
Coolant volume, (ea.), cu.ft.	1683
Secondary side design	
Design pressure, psia	1000
Design temperature, °F	650
Normal operating steam presure, full load, psia	850
Normal operating steam temperature, full load, °F	525.2
Blowdown flow (ea.), lbm/hr	4880
Steam flow (ea.), lbm/hr	5.635E6
Feedwater temperature, °F	431.5
Dimentions	
Overall height, including support skirt, ft.	62.4
Upper shell outside diameter, ft.	20
Lower shell outside diameter, ft.	13.75
Dry weight, lbs	1,004,000
Flooded weight, lbs	1,526,700
Operating weight, lbs	1,218,251

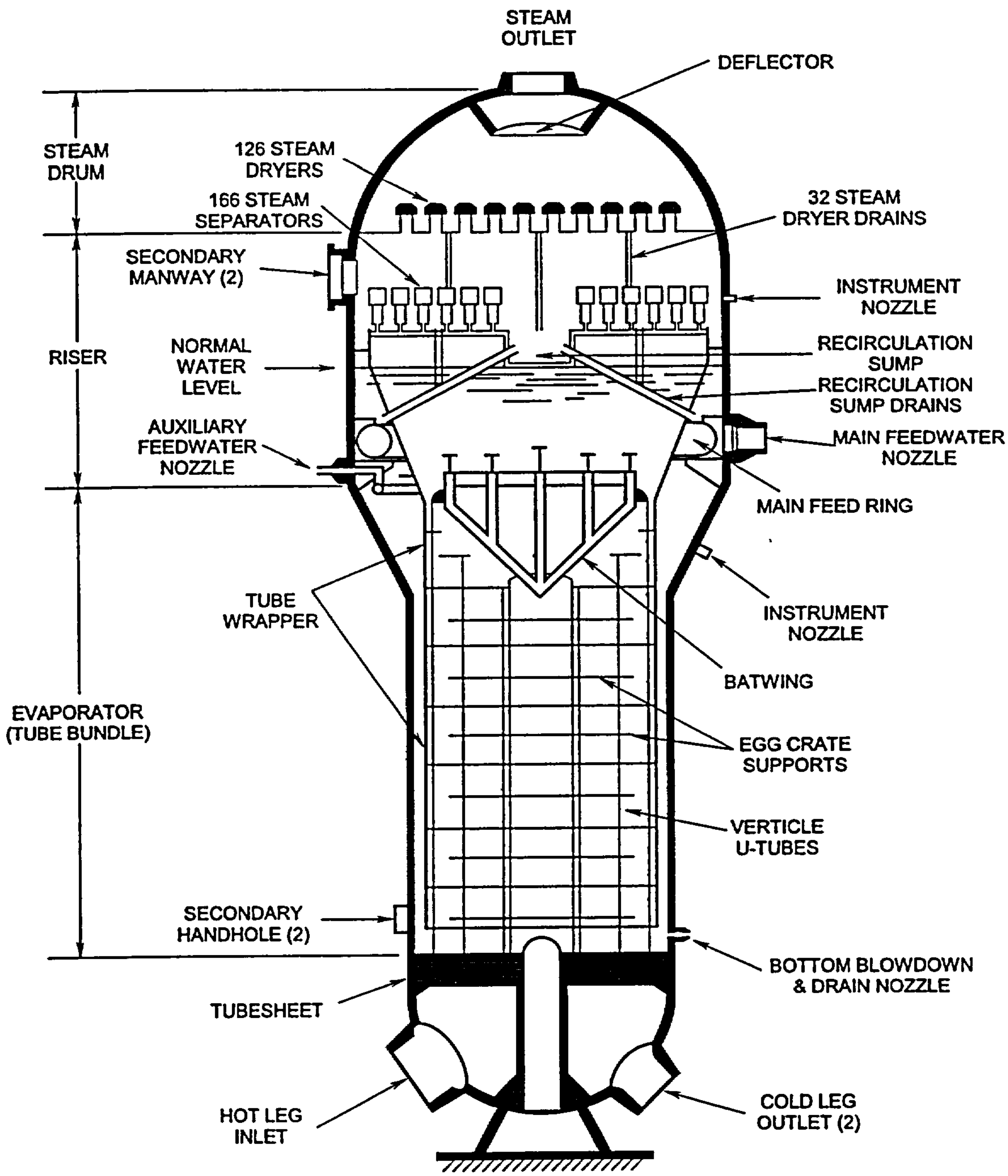

Figure 2.3-1 Steam Generator Secondary Side

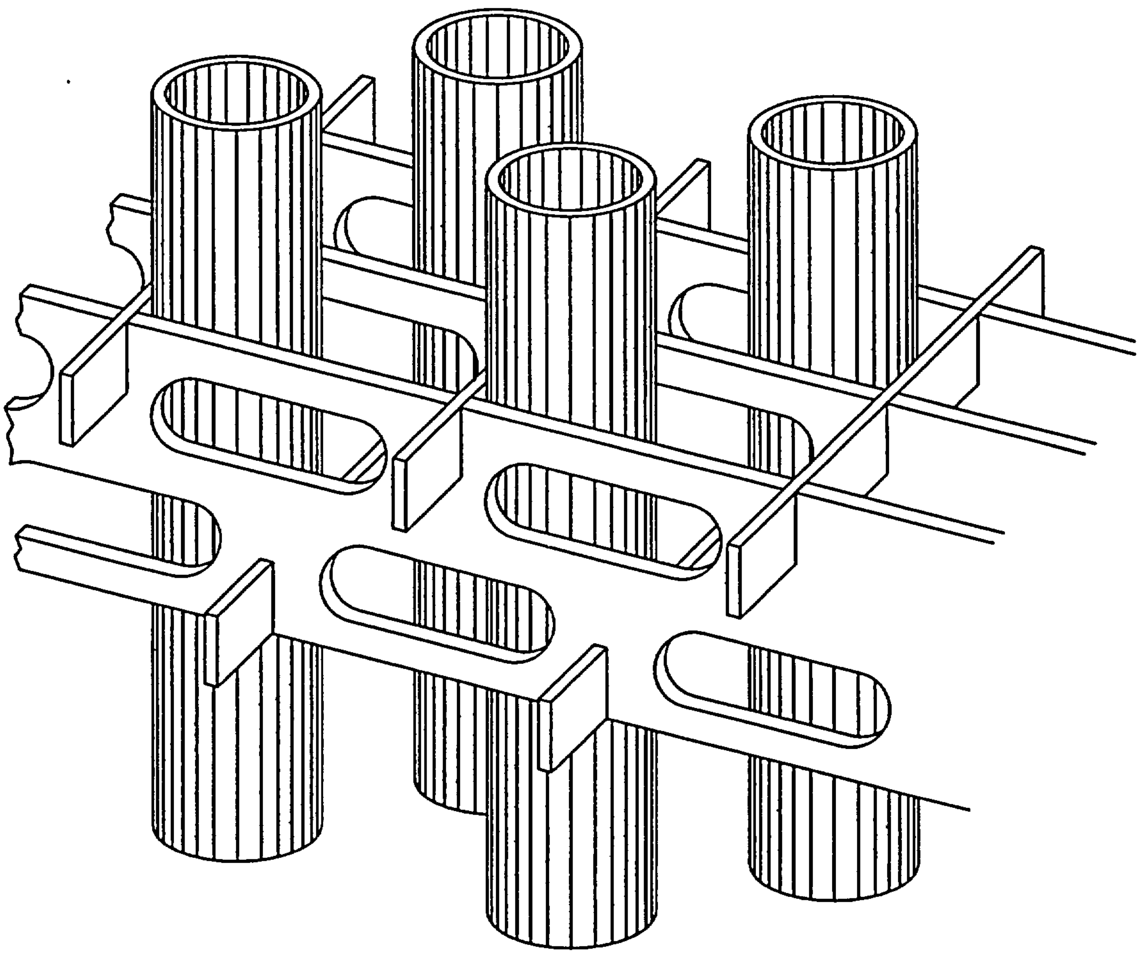

Figure 2.3-2 Steam Generator Eggcrate Tube Supports

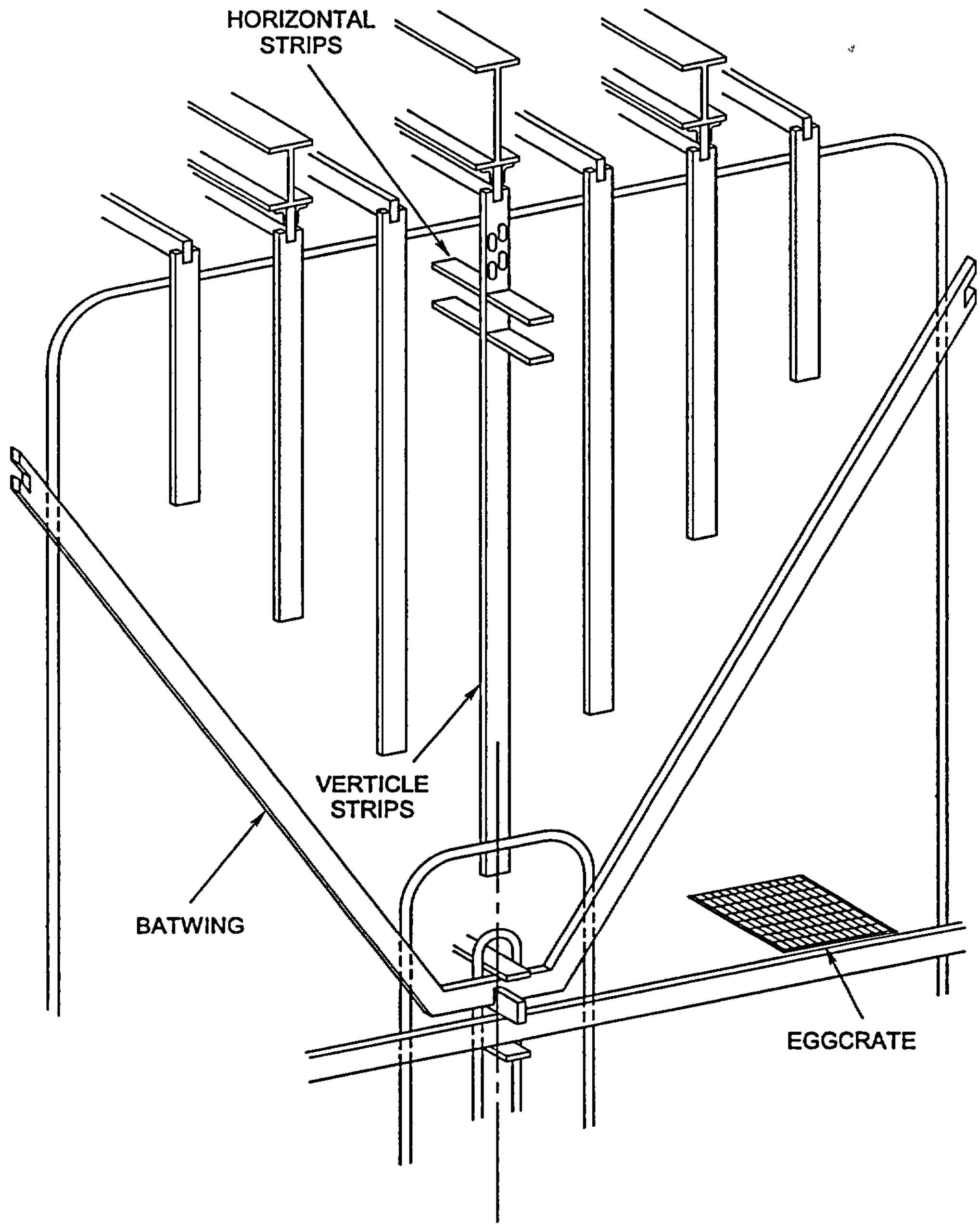

Figure 2.3-3 Bend Region Tube Supports

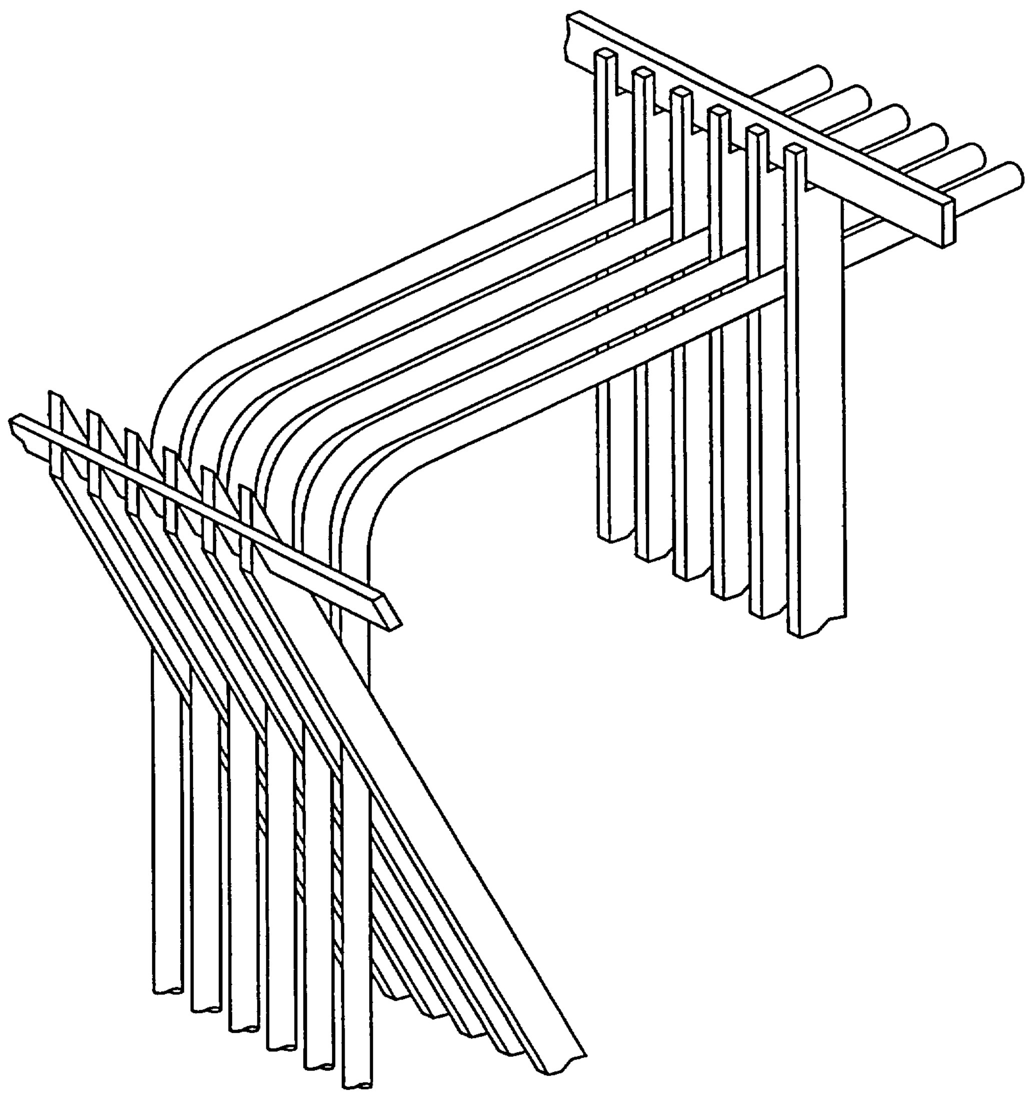

Figure 2.3-4 Batwings and Tube Supports

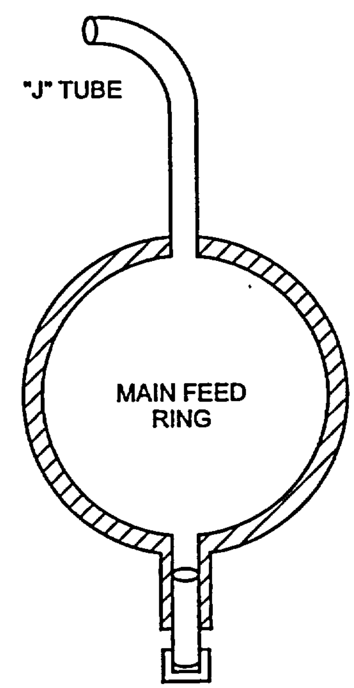

Figure 2.3-5 Cross-Section of Feed Ring Retrofitted with J-Tube

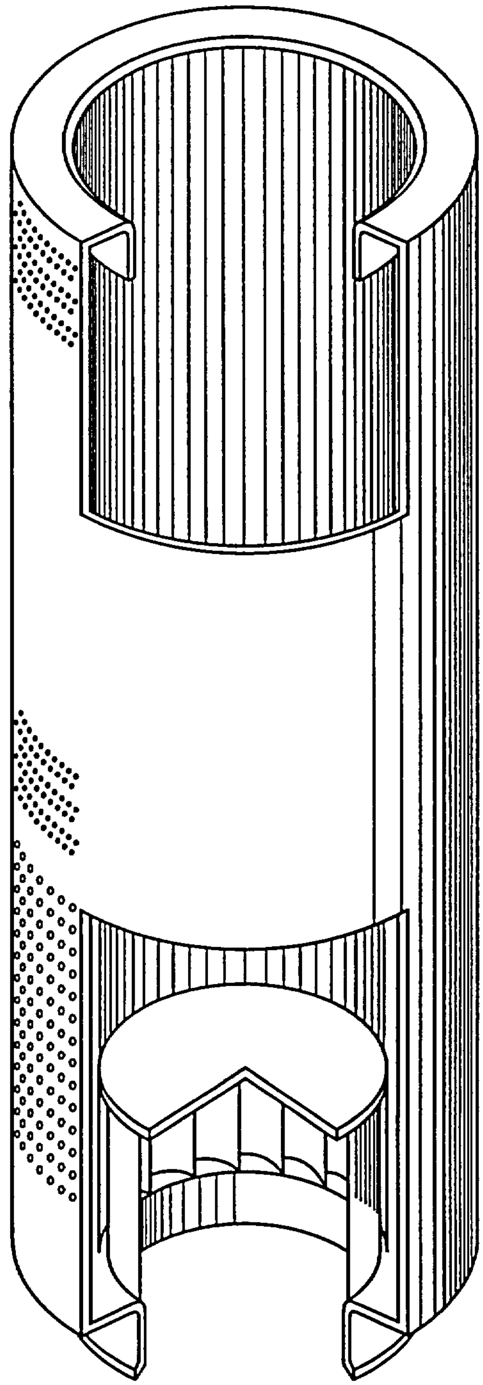

Figure 2.3-6 Centrifugal Steam Separators

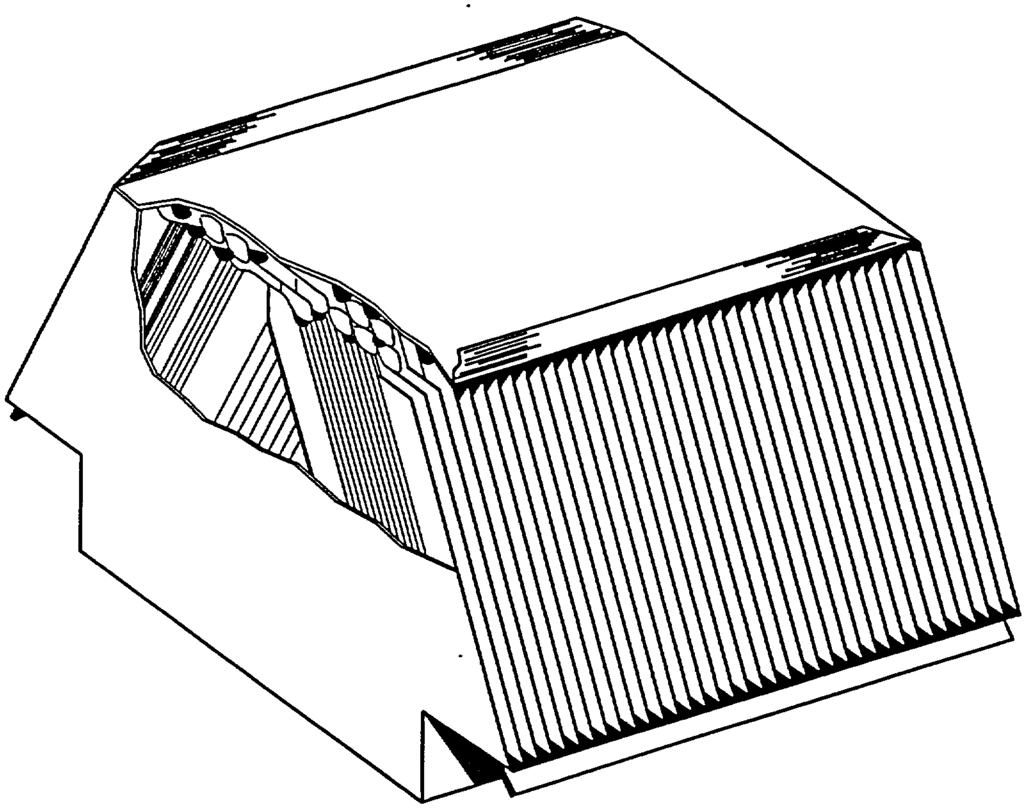

Figure 2.3-7 Chevron Steam Dryers

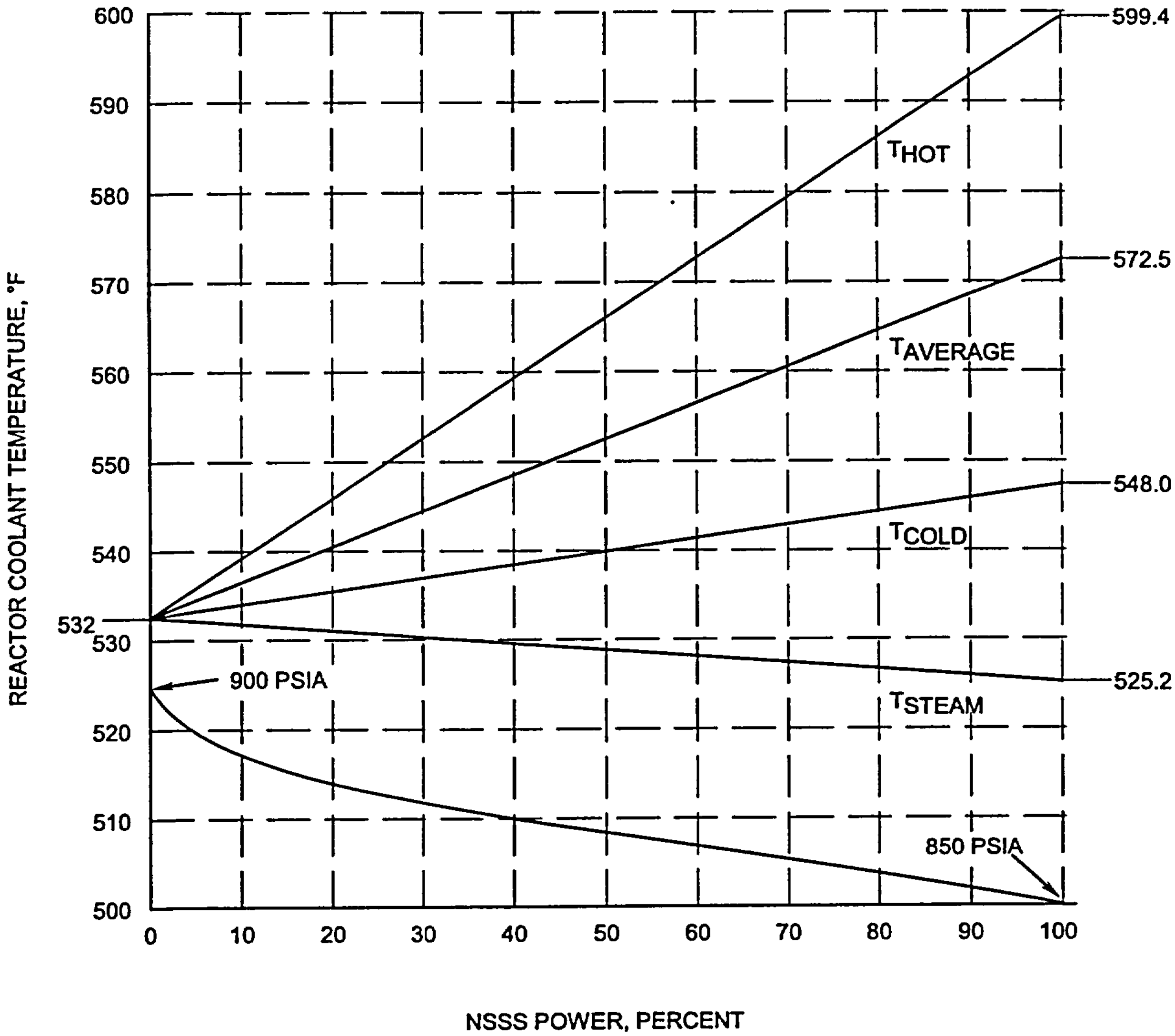

Figure 2.3-8 RCS Temperature Program

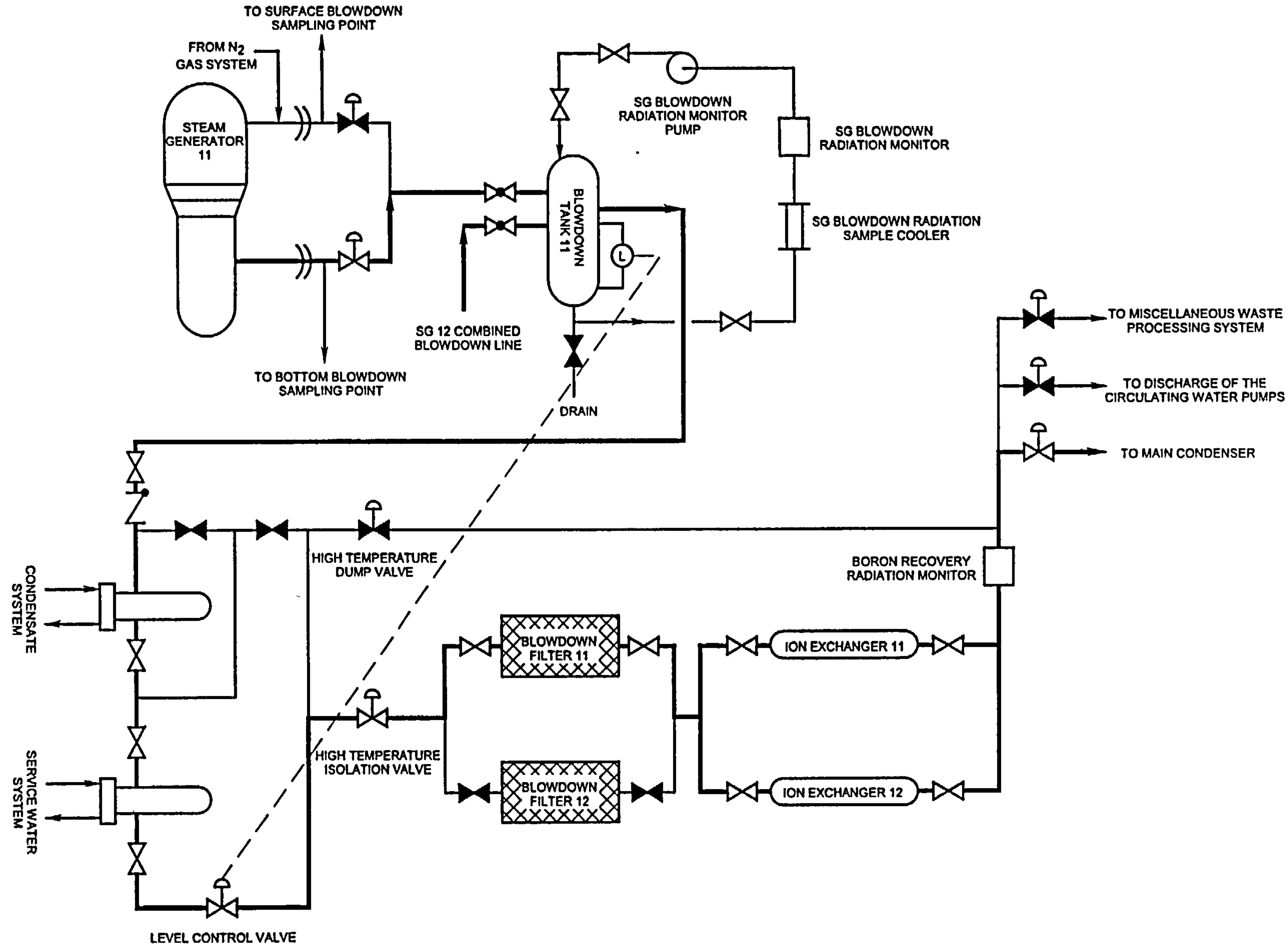

Figure 2.3-9 Steam Generator Blowdown and Recovery System

1000-0

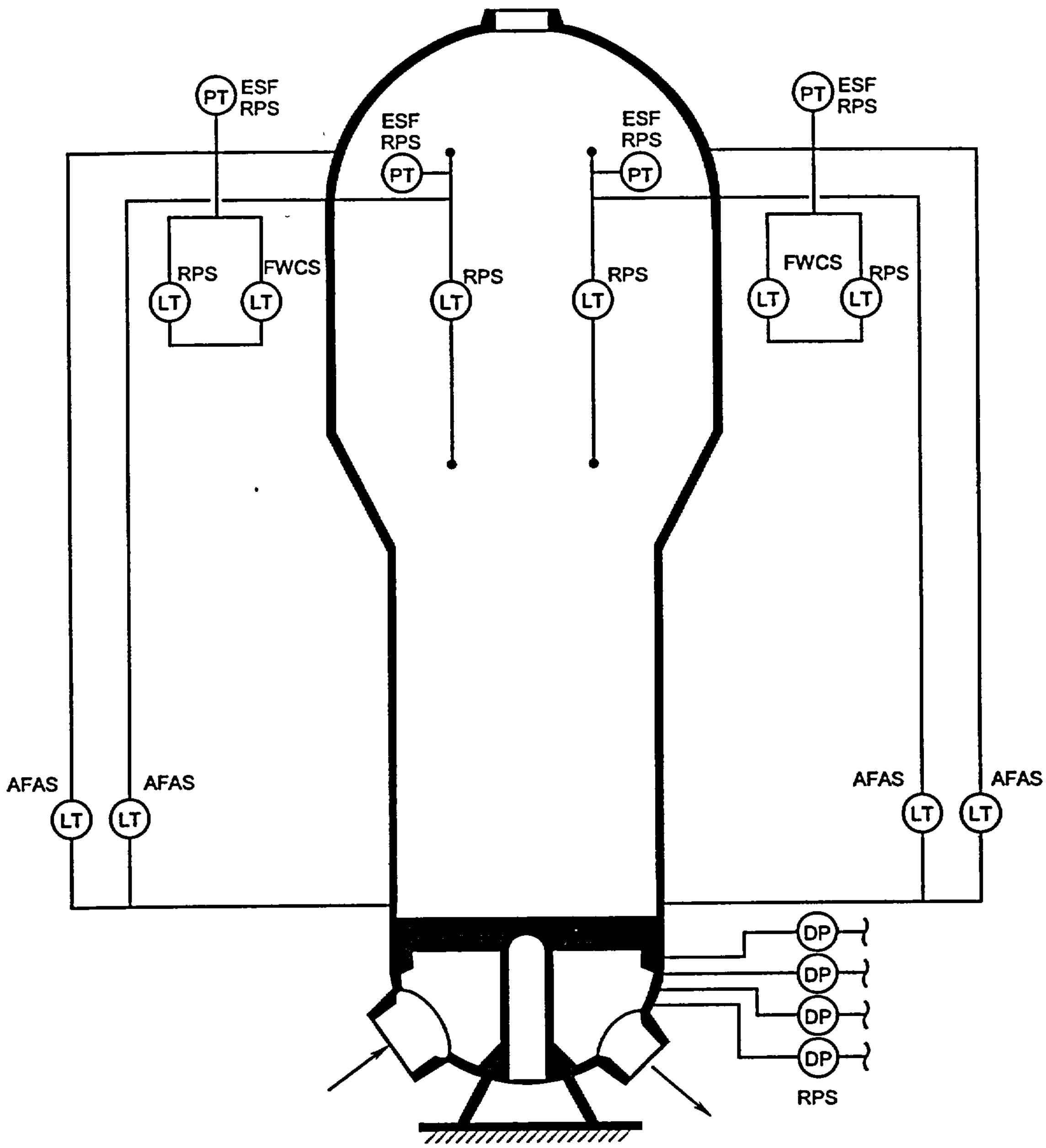

Figure 2.3-10 Steam Generator Instrumentation

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Chapter 3

CONTROL ELEMENT DRIVE MECHANISM

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3.0 CONTROL ELEMENT DRIVE MECHANISMS

Learning Objectives:

1. Describe the components in the control element drive mechanism (CEDM) that are a part of the RCS pressure boundary.

2. Describe the power supply to the CEDMs.

3. Explain the purposes of the control element assembly control and indication system (CEAC&IS).

4. List and state the purposes of the CEAC&IS interlocks.

5. Explain the various modes of operation of the CEAC&IS.

3.1 Introduction

The purposes of the control element assemblies are:

1. Provide sufficient negative reactivity to shutdown the reactor,

2. Provide reactivity additions to allow reactor start-ups and limited power escalations, and

3. Allow control of the reactor's axial flux distribution.

There are two (2) different types of CEAs installed in the core, shutdown and regulating. The forty shutdown CEAs are divided into three groups (A, B, and C) and are fully withdrawn during power operations. The shutdown CEAs are driven by a dual CEA drive mechanism (one mechanism controls the position of two CEAs). The thirty-seven regulating CEAs are divided into six (1, 2, 3, 4, 5, and 6) control groups that are withdrawn to at least the power dependent insertion limit (PDIL) during power operation. Each of the regulating CEAs has an individual drive mechanism.

3.2 CEA Mechanism Mechanical Construction

The CEA mechanism may be divided into three (3) sections. The first section is the drive shaft assembly. The second section is the CEDM pressure housing and drive unit. The final section is the coil assembly.

3.2.1 CEA Drive Shaft

The regulating CEA drive shaft (Figure 3-1) extends from the top of the CEA spider up through the CEA pressure housing and into the upper pressure housing. The drive shaft is coupled with the CEA spider by an expandable collet located at the bottom of the shaft assembly. An operating rod (located on the inside of the shaft) expands the fingers of the collet. The fingers of the collet contain lands that mate with grooves on the inside of the CEA spider hub. From the top of the CEA, the drive section continues upward to the pressure boundary housing. The portion of the drive shaft that is located on the inside of the pressure housing is grooved to allow the driving latches to position the CEA. The top extension of the drive shaft contains the necessary apparatus for the coupling and uncoupling of the CEA during refueling activities. A magnet is also located on this section of the drive shaft. The magnet opens and closes reed switches that are used in the position indication system.

The dual CEA coupling (Figure 3-2) consists of a yoke and two (2) collets. Each of the collets, located on either end of the yoke, is coupled to a shutdown CEA. The drive shaft connects to the center of the yoke. A magnet is also located at the top of the drive shaft and operates reed switches that are used to indicate the position of both of the CEAs that are attached to the drive shaft.

3.2.2 Pressure Housing and Drive Unit (Figure 3-3)

The bottom of the pressure housing is threaded onto the vessel head CEA nozzles. This vessel penetration is sealed by an omega seal and is also seal welded to insure vessel integrity. The upper pressure housing completes the pressure housing assembly.

The upper pressure housing is threaded into the pressure housing and also contains an omega seal. A ball vent assembly, used to remove air from the system, completes the pressure housing. Reactor coolant pressure extends from the CEA nozzle up to the ball vent assembly.

The motor assembly portion of the drive unit is shown in Figure 3-4. As shown in this figure, the motor housing contains necked down areas that concentrate magnetic lines of flux from the CEDM coils to the gripper latches. Two (2) drive latches or grippers are located inside of the motor assembly. The upper gripper and the lower gripper are magnetically operated and position the CEA during withdrawal and insertion. A spring loaded anti-ejection gripper is included in the CEA design to minimize the possibility of a CEA ejection accident. All of the gripper fingers fit into the grooves of the CEA drive shaft.

3.2.3 Coil Assembly

Five (5) electromagnetic coils, located on the outside of the pressure housing, are used to hold and move the CEA. The following list provides the function and names of each of the coils.

1. The lift coil is used to move the CEA drive shaft and to disengage the anti-ejection gripper.
2. The upper gripper coil is used to hold the CEA.
3. The pull down coil is used to reposition the upper gripper for the next CEA step.
4. The load transfer coil transfers the load between the upper and lower grippers during CEA movement.
5. The lower gripper holds the CEA during the intermediate steps of a movement sequence.

The action of these coils is best illustrated by describing CEA withdrawal and insertion sequences.

3.2.3.1 Withdrawal Sequence (Figure 3-5, 3-6)

The CEA is moved in discrete three-quarter (3/4) inch steps as follows:

1. Initial conditions, the upper gripper is energized and holding the CEA. The anti-ejection gripper in also engaged. (Figures 3-5, 3-6(a))
2. The lift coil is energized releasing the anti-ejection grippers and pulling the CEA up three-quarters (3/4) of an inch. (Figure 3-6b).
3. The lower gripper is energized to hold the CEA in the new position. (Figure 3-6c)
4. The load transfer coil is energized pulling the lower gripper up one-thirty second (1/32) of an inch. This transfers the CEA load to the lower gripper. (Figure 3-6d)

5. The lift coil and upper gripper coil de-energize and the pull down coil is energized. This action pulls the upper gripper back to its original position and allows the anti-ejection gripper fingers to engage the drive shaft. (Figure 3-6e)

6. The upper gripper coil is energized and the latches engage the drive shaft. (Figure 3-6f)

7. The load transfer coil is de-energized transferring the load to the upper gripper. (Figure 3-6g)

8. The lower gripper is de-energized, returning the mechanism to the hold mode. (Figure 3-6h)

One withdrawal sequence has been completed.

3.2.3.2 Insertion Sequence (Figure 3-5,3-7)

Again, the CEA is inserted in three-quarter (3/4) inch steps. The insertion sequence follows:

1. The lower gripper coil is energized. The lower gripper latches contact the drive shaft. (Figure 3-7a)

2. The load transfer coil is energized and the lower gripper is pulled up one-thirty second (1/32) of an inch. This places the CEA load onto the lower grippers. (Figure 3-7b)

3. The upper grippers are de-energized. (Fig 3-7c)

4. The lift coil is energized, the anti-ejection latch is disengaged, and the upper gripper is pulled up three-quarters (3/4) of an inch. (Figure 3-7d)

5. The upper gripper coil is energized and the upper gripper latches engage the drive shaft. (Figure 3-7e)

6. The load transfer coil is de-energized transferring the CEA load to the upper grippers. (Figure 3-7f)

7. The lower gripper coil is de-energized causing the lower gripper latches to disengage. (Figure 3-7g)

8. The CEA is lowered three-quarters (3/4) of an inch by momentarily energizing the pull down coil. The pulldown coil overcomes the lift coil allowing the CEA to insert. (Figure 3-7h)

9. The lift coil is then de-energized and the anti-ejection grippers engage the drive shaft. The mechanism is now in the hold mode and one insertion sequence has been completed.

3.3 Control Element Assembly Control and Indication System (CEAC&IS)

The Control Element Assembly Control and Indication System (CEAC&IS) generates the electrical signals that cause the CEDMs to raise, lower, or hold the CEAs. It includes the controls, logic, interlocks, indications, and alarms that ensure proper operation of the CEAs. The positions of the CEAs are controlled remotely from signals originating in the main control room and can be controlled individually or as a group. The CEAC&IS includes the CEDS Control Panel, CEA Logic Cabinet, CEA Motor Generator sets and associated Motor Generator control cabinets. Figure 3-8 illustrates the interrelationship of the CEAC&IS components and other plant instrumentation and control systems.

3.3.1 CEDS Logic

All withdrawal or insertion signals generated for the CEDMs at the CEDS control panel pass through the CEA logic cabinet. In this cabinet, CEA control signals are directed to the correct group and/or individual CEAs and then modified by protective interlocks and controls.

The CEA logic cabinet includes four logic panels which further contain logic modules. Logic modules are provided for group and individual CEA logic, group and mode selection logic, and several logic control modules for interlock and control functions. The interlock functions include CEA Motion Inhibit (CMI), CEA Withdrawal prohibit (CWP), Automatic Withdrawal Prohibit (AWP), CEA limit switch relay and permissives, and regulating bank sequencing system interlocks. The control functions include circuitry for the Reactor Regulating System (RRS) and the plant computer interfaces.

The CEA coil power programmers deliver control power to the coils of the CEDM. There is one coil power programmer for each CEDM which controls the time, pulse duration, and level of electrical current supplied to the coils of the CEDM. The coil power programmers receive power from the CEA motor generator sets.

The coil power programmer is comprised of the timing logic, the power switch, and the up-down counter sections. The timing logic section generates the precise timing signals for CEA motion while the power switch effectively amplifies these timing signals by switching the current from one coil to another coil. The lift and pull-down coils have two separate timing controls, one for the withdrawal cycle and one for the insertion cycle. Also each CEDM coil uses two different current levels, except the pull-down coil which uses only one current level. A typical timing control circuit for each CEDM consists of three timers. One timer is used to set the time from the beginning of the cycle until current flow is initiated into the coil, one timer is used to set the time duration for high current flow into the coil, and one timer is used to set the time duration for low current flow into the coil.

3.3.2 CEA Power Supply (Figure 3-9)

The power for the CEA coils comes from redundant motor-generator (MG) sets. The MG set motor is a 480 Vac, 3 phase, 220 hp induction motor that receives its power from a non-class 1E bus. The motor drives a 240 Vac, 3 phase, 60 Hz, generator. A flywheel is installed on the MG set to provide for a constant power output during momentary power upsets. The flywheel provides sufficient rotating inertia to maintain generator output frequency above 59 Hz. for three-tenths (3/10) seconds and above 58 Hz. for one (1) second after power interruption. The output of the generator is routed to the reactor trip circuit breakers via an output breaker. Control cabinets are installed to allow MG set start-up, shutdown and generator synchronization.

The diverse scram system (DSS) interfaces with the MG sets through the motor load contactor (controller). The DSS receives inputs from the four (4) pressurizer pressure safety channels and will actuate when two (2) out of the four (4) pressurizer pressure channels sense a pressurizer pressure of 2450 psia. When the DSS actuates, it de-energizes the MG set motor controller. When the motor loses power, the generator output drops to zero and power is lost to the CEAs. The loss of power to the CEAs allows the CEAs to fall into the core. The DSS was a design backfit and is required to mitigate the consequences of an anticipated transient without scram (ATWS).

3.3.3 Reactor Trip Circuit Breakers

As shown on Figure 3-9, there are nine (9) circuit breakers installed between the MG set output breakers and the coils of the CEAs. The 9 circuit breaker is used to ensure MG set synchronization is maintained regardless of the order of the closure of the remaining eight (8) breakers. To illustrate the importance of the 9 breaker, assume that all circuit breakers are open with the exception of the MG output breakers. Note that breakers 1, 2, 4, 5, 6, and 8 can be shut in any order; however, when either breaker 3 or 7 is closed, the MG sets are paralleled. There is an extremely large probability that the MG sets will not be synchronized when either of these breakers are closed. If the 9 breaker is closed, the MG sets cannot be paralleled out of phase by closing breakers 1 through 8 in any order.

Circuit breakers (1-8) are the reactor trip circuit breakers (RTBs). These breakers are controlled by the reactor protection system (RPS). When a reactor trip signal is generated by the RPS, the RTBs will open.

These breakers can be opened by two methods. First, an under voltage coil is deenergized causing the breaker to open. Second, the breaker shunt trip coil is energized and the breaker will open. Regardless of how the circuit breakers are opened, deenergizing power to the CEA coils allows the CEAs to drop into the core.

Power from the reactor trip circuit breakers is routed to the CEAs via two distribution buses. About one half of the CEAs are powered from each bus.

3.3.4 CEA Distribution Buses (Figure 3-10)

The power distribution from one (1) of the two (2) CEA buses to the CEAs is shown. Two (2) under voltage coils monitor the power supplied to the bus. When a reactor trip occurs, the under voltage coils sense the loss of power to the CEAs. The coils provide reactor trip information to the turbine trip system (turbine trip on reactor trip) and the feedwater control system (turbine trip or reactor trip over ride).

The CEAs are divided into subgroups of four (4) or five (5) CEAs. Power to each subgroup is routed through a subgroup breaker. There are ten (10) subgroups supplied by each distribution bus. Each subgroup breaker supplies up to five CEAs via individual CEA breakers.

Power from an individual CEA breaker travels through a coil switch to the CEA coil. The coil switch is a set of three silicone controlled rectifiers (SCRs) that are controlled by the control element assembly control and indication system (CEAC&IS).

In addition to the coil switch power supply, the CEAs may be powered from the hold bus. The hold bus is a maintenance device. A subgroup of CEAs may be transferred to the hold bus, at the CEA Logic Cabinets, in order to perform maintenance on the CEA coil switches or CEAC&IC logic.

The hold bus supplies power to the upper gripper coil. If the RTBs open, power will be lost to the hold bus. Any CEAs that are receiving power from the hold bus will be de-energized.

3.4 CEA Position Indication Systems

Three (3) independent CEA position indication systems are installed to provide CEA position information and interlocks for the CEAC&IS. The first position indication system is called the primary CEA position indication system. This system utilizes the plant computer to count the up and down pulses that are supplied to the CEA coils. The second position indication system determines CEA position by magnetic switches that are opened and closed by the magnetic section of the CEA drive shaft. This is the secondary CEA position indication system. The final position indication system also uses magnetic switches that are opened and closed by the magnetic section of the CEA drive shaft. These switches supply position information to the CEA mimic display, and are independent from the secondary CEA position indication system.

3.4.1 Primary CEA Position Indication System

The primary CEA position indication system monitors the up and down pulses sent to the CEA coils. These pulses are counted by an up-down counter in the plant computer. Each up or down pulse represents a three-quarter (3/4) inch change in CEA position. The plant computer supplies position information to nine (9) digital meters, one (1) for each CEA group, located in the control room adjacent to the CEA control station. Each of the nine (9) digital meters displays position information for a selected CEA in its associated group. The selected CEA is determined by switches on the CEAC&IS panel. The plant computer can also provide a printout of all group and individual CEA positions.

In addition to position information, the primary CEA position indication system provides signals that are used to control the CEAs. An upper CEA group stop (UCS) is supplied to each of the nine (9) CEA groups to stop outward group motion when the lowest CEA in the group reaches 133.5 inches. Further CEA withdrawal is allowed in the manual individual mode of control. A lower CEA group stop (LCS) is also provided to each of the nine (9) CEA groups to stop inward group motion when the highest CEA in the group reaches 4.5 inches. Again, further CEA insertion is allowed in the manual individual mode.

The primary CEA position indication system also provides alarms to warn the operator of CEA misalignments. If the difference between the highest and lowest CEA in a group exceeds three and three-quarters (33/4) inches, the CEA position four (4) inch deviation alarm is annunciated. If the difference between the highest and lowest CEA in a group exceeds seven and one-half (7 1/2) inches, the CEA position eight (8) inch deviation alarm is annunciated. The first of these alarms gives the operating staff time to correct CEA misalignment before the technical specification limit of seven and one-half (7 1/2) inches is reached. The second alarm informs the operator that the technical specification limit has been reached or exceeded.

A third set of alarms provided by the primary CEA position indication system associated with power distribution is the power dependent insertion limit (PDIL) alarms. The PDIL alarms compare the CEA position of each regulating group with reactor power. The power signal used in the alarm algorithm is supplied from the computer calculation of thermal power. If the CEA position approaches the pre-programmed position for the existing reactor power, a pre-PDIL (PPDIL) alarm is generated. This alarm alerts the operator to the potential of exceeding the technical specification CEA insertion limit. If CEA position equals or exceeds the pre-programmed position for the existing reactor power, the PDIL alarm is annunciated. When this alarm is annunciated, technical specification limits may have been exceeded. Both the PPDIL and the PDIL alarms are bypassed if power, as sensed by wide range logarithmic channels, is $<10^{-4}\%$.

The final limit provided by the primary CEA position indication system is the exercise limit. The ability to move the CEAs is a technical specification surveillance requirement. Insertion of the CEAs from a fully withdrawn position to the exercise position of 129 inches complies with the technical specification requirement.

3.4.2 Secondary CEA Position Indication System (Figure 3-11)

The secondary CEA position indication system is redundant to, and completely independent of, the primary CEA position indication system. The position signals for the secondary CEA position indication system are initiated by reed switch position transducers (RSPTs) that are housed in the shroud assembly of the CEDMs. The switches are positioned at one and one-half (1 1/2) inch intervals along the length of the CEDM shroud assembly and are wired into a voltage divider network. The output of the voltage divider is a stepped voltage signal proportional to CEA position that is supplied to a cathode ray tube (CRT). The CRT provides two indications of CEA position. The first indication is a vertical bar graph that provides a simultaneous display of all of the CEAs in the core by group or all groups. The second indication is a digital readout of the CEA position.

In addition to position indication, the secondary CEA position indication system also provides signals that are used for alarms and interlocks. The first alarm provided by the secondary CEA position indication system deals with CEA sequencing. This alarm monitors the regulating group position to determine if too much overlap exists or if the correct CEA sequence is being maintained. If, between successive groups, the lowest CEA in the preceding group is below the upper sequential permissive (USP) of 93 inches and the highest CEA in the succeeding group is above the lower sequential permissive (LSP) of 54 inches then an out of sequence alarm will be generated. Additionally, if the difference between successive CEA groups is less than 79 inches , or if the wrong CEA group is moving, then an out of sequence alarm will also be generated. The secondary CEA position indication system also provides CEA deviation alarms.

Each CEA group deviation alarm circuit consists of a high select unit, a low select unit, a summing amplifier, and two (2) bistables. The output of the RSPTs is supplied to the high select unit and the low select unit. The high select unit passes only the signal from the highest CEA position, and the low select unit passes the signal from the lowest CEA position. The summing amplifier subtracts the lowest CEA position from the highest CEA position and sends the result to the two (2) bistables. The first bistable determines if the difference between the highest and lowest CEA exceeds four (4) inches. The second bistable determines if the difference between the highest and lowest CEA exceeds eight (8) inches. The output of the bistables is routed to the secondary CEA four (4) inch deviation and the secondary CEA eight (8) inch deviation annunciators, respectively.

The secondary CEA position indication system also provides power dependent insertion limit alarms. The PDIL alarms also compare the CEA position of each regulating group with reactor power. Except that the power signal used in the secondary CEA position system alarm circuitry is supplied by the RPS and is the highest of ΔT power or linear power range nuclear power.

Both the PPDIL and the PDIL alarms are bypassed if power, as sensed by wide range logarithmic channels, is less than $10^{-4}\%$.

Two (2) interlocks are provided by the secondary CEA position indication system to ensure that shutdown margin and power distribution assumptions are maintained. The shutdown groups cannot be inserted until all regulating CEAs are inserted to <10 inches. This interlock is called the shutdown CEA insertion permissive and is annunciated on the control board. Likewise, the regulating group CEAs cannot be withdrawn unless all shutdown CEAs are withdrawn to at least 129 inches. This interlock is called the regulating CEA withdrawal prohibit and is also annunciated on the control board.

3.4.3 CEA Mimic Indication (Figure 3-12)

The CEA mimic display system consists of a core mimic panel and lights that represent CEA location and status. There are 57 light assemblies (20 dual CEA indications and 37 single CEA indications). The colored lights are controlled by reed switches that are independent of the secondary CEA position reed switches.

Each light assembly has four (4) different colored lights. The light colors are:

1. Red, indicating a fully withdrawn condition,
2. White which is the operating band for a regulating CEA,
3. Green, indicating a fully inserted condition, or
4. Amber, indicating a dropped CEA and
5. Blue which is the exercise limit for a shutdown CEA

The red light is energized when the CEA is at its upper electrical limit (UEL) of 135 inches. When a CEA reaches this position, logic circuits prevent further withdrawal commands.

The green light is energized when the CEA is at its lower electrical limit (LEL) of three and one-half (3 1/2) inches. When a CEA reaches this position, logic circuits prevent further insertion.

The white lights are energized on the regulating CEAs when the CEAs are between the upper and lower electrical limits. For shutdown CEAs, the white light is replaced with a blue exercise lamp that is illuminated when the shutdown CEA is < 129 inches.

3.5 CEAC&IS

The CEAC&IS allows manual or automatic control of the CEAs.

The following is a listing of CEA groups, functions and number of CEAs assigned to a group:

Group	Function	# of CEAs
A	Shutdown	16
B	Shutdown	8
C	Shutdown	16
1	Regulating	8
2	Regulating	4
3	Regulating	4
4	Regulating	8
5	Regulating	4
6	Regulating	9

The shutdown groups can only be controlled in manual while the regulating groups can be controlled manually or automatically. Manual or automatic control is determined by selections made at the CEAC&IS control panel.

3.5.1 CEAC&IS Control Panel

The CEAC&IS panel (Figure 3-13) provides selection capability for the desired mode of CEA operation and CEAC&IS indication on the core mimic panel. The use of the different CEAC&IS control modes is best illustrated by discussing the start-up and power escalation of the reactor.

3.5.2 Reactor Start-up

The initial conditions for the reactor start-up are:

1. The unit is in operating mode 3 and

2. An estimated critical position has been calculated, and a plant start-up is permitted by technical specifications.

The first step in the reactor start-up is to withdraw the shutdown groups to their fully withdrawn position. The withdrawal of the shutdown groups is accomplished in the manual group mode of control.

3.5.2.1 CEA Manual Group Control

Manual group control is accomplished by selecting the desired group of CEAs to be withdrawn by pressing the appropriate switch located in the group selection section of the CEAC&IS panel and selecting the manual group (MG) mode push-button located in the mode selection section of the CEAC&IS. The shutdown bank withdrawal is accomplished by selecting the A position on the group select, selecting MG on the mode select, and placing the manual control switch to the withdraw position.

Outward CEA motion will be permitted provided a CEA withdrawal prohibit (CWP) is not present. A CWP signal is generated when two (2) out of four (4) pre-trip signals are generated by either high pressurizer pressure, high start-up rate or thermal margin low pressure pre-trip bistables in the RPS. Outward CEA motion will continue until the upper CEA group stop (UCS) is reached. The upper group stop is generated by the plant computer when the selected CEA group reaches 133.5 inches withdrawn. The 133.5 inch position is almost fully withdrawn and is used as an interlock to stop rod motion. When group A reaches the upper group stop, the operator will pull each rod to the upper electrical limit (UEL) in the manual individual mode of control. Shutdown group Band Shutdown group C CEAs will be fully withdrawn in the same manner. The speed of the shutdown CEAs is 20 inches per minute in all modes of control.

The remaining interlocks in manual group control are:

1. The lower group stop (LCS) and

2. The lower electrical limit (LEL).

The lower CEA group stop stops all inward CEA motion when the plant computer calculates that the group has reached the four and one-half (4 1/2) inch position. The lower electrical limit is a reed switch actuated interlock that stops individual CEA motion commands when the CEA is inserted to three and one-half (3 1/2) inches from the bottom of the core.

3.5.2.2 Manual Individual Control

The manual individual control mode allows any CEA to be individually positioned. To withdraw the shutdown groups from the upper group stop to the upper electrical limit, the following steps are necessary:

1. The manual individual (MI) mode is selected.

2. The desired CEA is selected by depressing its selector switch located in the individual CEA selection section of the CEAC&IS panel. This switch also determines the CEA position that is displayed by the digital meter associated with the primary CEA position indication system.

3. The manual control switch is positioned to the withdraw position, and the CEA is pulled to the upper electrical limit.

The above sequence is repeated for each shutdown group CEA. In addition to withdrawing the shutdown groups to the upper electrical limit, the manual individual mode is used to recover dropped CEAs and is used during CEA testing.

The interlocks in the manual individual mode are the upper and lower electrical limits for all full length CEAs. These interlocks were described in the previous section.

Now that the shutdown groups are withdrawn to the upper electrical limit, the control groups are ready to be withdrawn. This evolution is accomplished in the manual sequential mode of control.

3.5.2.3 Manual Sequential Control

The manual sequential (MS) mode is used only for the regulating groups. This mode of CEA control is selected after all the shutdown banks have been withdrawn to the upper electrical limit. When the operator selects MS and positions the manual control switch to the withdraw position, control group 1 begins to move outward from the core. When group 1 reaches 93 inches withdrawn, the upper sequential permissive (USP) is reached. The upper sequential permissive allows group 2 outward motion. Group 1 and group 2 move simultaneously until group 1 reaches the upper group stop (133.5"). When group 1 is at the group stop, group 2 should be at 40.5 inches. Group 2 continues to move outward until it reaches 93 inches, then groups 2 and 3 move out together.

The overlapping of motion between successive regulating groups allows for a more linear reactivity addition by the CEAs. The overlapping of the CEAs is applicable to all regulating groups. The regulating groups are withdrawn until criticality is achieved. Before continuing with the escalation of reactor power, two features of the manual sequential mode of control need to be described.

First, the overlapping of the regulating groups also occurs during CEA insertion. To illustrate the overlapping, assume that all CEAs are fully withdrawn. When the manual control switch is placed in the insert position, group 6 starts to move into the core. When group 6 reaches 54 inches, group 5 starts to drive in. Simultaneous inward motion continues until group 6 reaches the lower group stop (4 1/2 inches). Group 5 inward motion continues until group 5 reaches the 54 inch position at which time group 4 inward motion starts. The 54 inch position (calculated by the plant computer) is called the lower sequential permissive and is applicable to all regulating groups. The withdrawal and insertion speed of the regulating group CEAs is 30 inches per minute.

The interlocks that are applicable in the manual sequential mode are:

1. Control element assembly withdrawal prohibit (CWP),

2. The upper and lower CEA group stops (UCS, LCS) and

3. The upper and lower electrical limits (UEL, LEL).

All CEA interlocks are summarized in Table 3-1.

After criticality is achieved in the manual sequential mode, power escalation to 15% reactor power is accomplished by CEA withdrawal. At 15%, the automatic sequential mode of operation may be selected.

3.5.2.4 Automatic Sequential Control

In the automatic sequential mode of operation the CEAs are positioned by the reactor regulating system (RRS, see Chapter 4). The RRS commands CEA motion in order to maintain Tavg at its desired value. Automatic outward (AR- automatic raise) and automatic insertion (AL- automatic lower) commands are generated by the RRS to cause the regulating group CEAs to move at two different rates. The low rate is three (3) inches/minute, while the high rate is 30 inches/minute. Also, the CEAs are overlapped in the sequence described in the previous section.

In the automatic sequential mode of control, a new interlock feature is introduced. The interlock is an automatic withdrawal prohibit (AWP) generated by the RRS. AWPs are generated by two conditions. The first condition is a high cold leg temperature (high Tc) of 548°F. The purpose of this interlock is to prevent exceeding the departure from nucleate boiling ratio (DNBR) cold leg temperature value. The second AWP signal is a large difference between actual and desired Tavg (Tavg-Tref). If Tavg is greater than Tref by 5°F, an AWP signal stops automatic outward CEA motion. This interlock prevents a further increase in the power mismatch between the RCS and secondary systems.

3.6 Summary

The control element assemblies provide sufficient reactivity to shutdown the reactor, provide reactivity additions to allow reactor start-ups and power escalations, and to allow control of the reactors axial flux distribution.

There are two (2) categories of CEAs installed in the core. The forty shutdown CEAs are divided into three (3) groups and are operated by dual drive mechanisms. The thirty-seven regulating CEAs are divided into six (6) groups and each has an individual drive mechanism. Each CEA drive mechanism forms a portion of the RCS pressure boundary and is operated from the reactivity control panel in the main control room.

The CEA control system incorporates the capability to operate the CEAs in different modes as selected by the operator at the CEAC&IS.

TABLE 3-1
CEA INTERLOCKS

	Shutdown	Regulating
Primary Position Indication System (computer/pulse counting)		
Upper Sequential Permissive (USP)	93 inches	93 inches
Lower Sequential Permissive (LSP)	54 inches	54 inches
Upper Group Stop (UCS)	133.5 inches	133.5 inches
Lower Group Stop (LCS)	4.5 inches	4.5 inches
CEA Group Deviation	4 and 8 inches	4 and 8 inches
CEA Out of Sequence Alarm (difference between sucessive groups)	N/A	79 inches or wrong group moving
Secondary Position Indication System (RSPTs)		
CEA Group Deviation	4 inches	4 inches
CEA Out of Sequence Alarm (difference between sucessive groups)	N/A	79 inches or wrong group moving
Regulating CEA Withdrawal Prohibit	Any CEA < 129 inches	N/A
Shutdown CEA Insertion Permissive	N/A	All Regulating group CEAs <10 inches
CEA Motion Inhibit	4 inch deviation	4 inch deviation
CEA Mimic (RSPTs)		
Upper Electrical Limit (UEL)	135 inches	135 inches
Lower Electrical Limit (LEL)	3.5 inches	3.5 inches
Dropped CEA	0 inches	0 inches
Shutdown CEA Exercise Limit	< 129 inches	

CONTROL ELEMENT DRIVE SYSTEM INTERLOCKS

CEA Withdrawal Prohibits (CWP)

Two-out-of-four coincident RPS pre-trips on any of the following:
- Thermal Margin Low Pressure (50psia above setpoint)
- High Start-up Rate (1.5 dpm)
- High Pressurizer Pressure (2350 psia)

CEA Motion Inhibit (CMI)

- Regulating group out of sequence
- Secondary 4 inch CEA deviation
- Regulating group motion prohibit
- Shutdown group insertion prohibit
- Secondary power dependant insertion limit

Automatic Withdrawal Prohibits (AWP)

- High Tc of 548°F as sensed by RRS RTDs (DNBR protection)
- High Tavg - Tref of 5°F as calculated by the RRS (power mismatch).

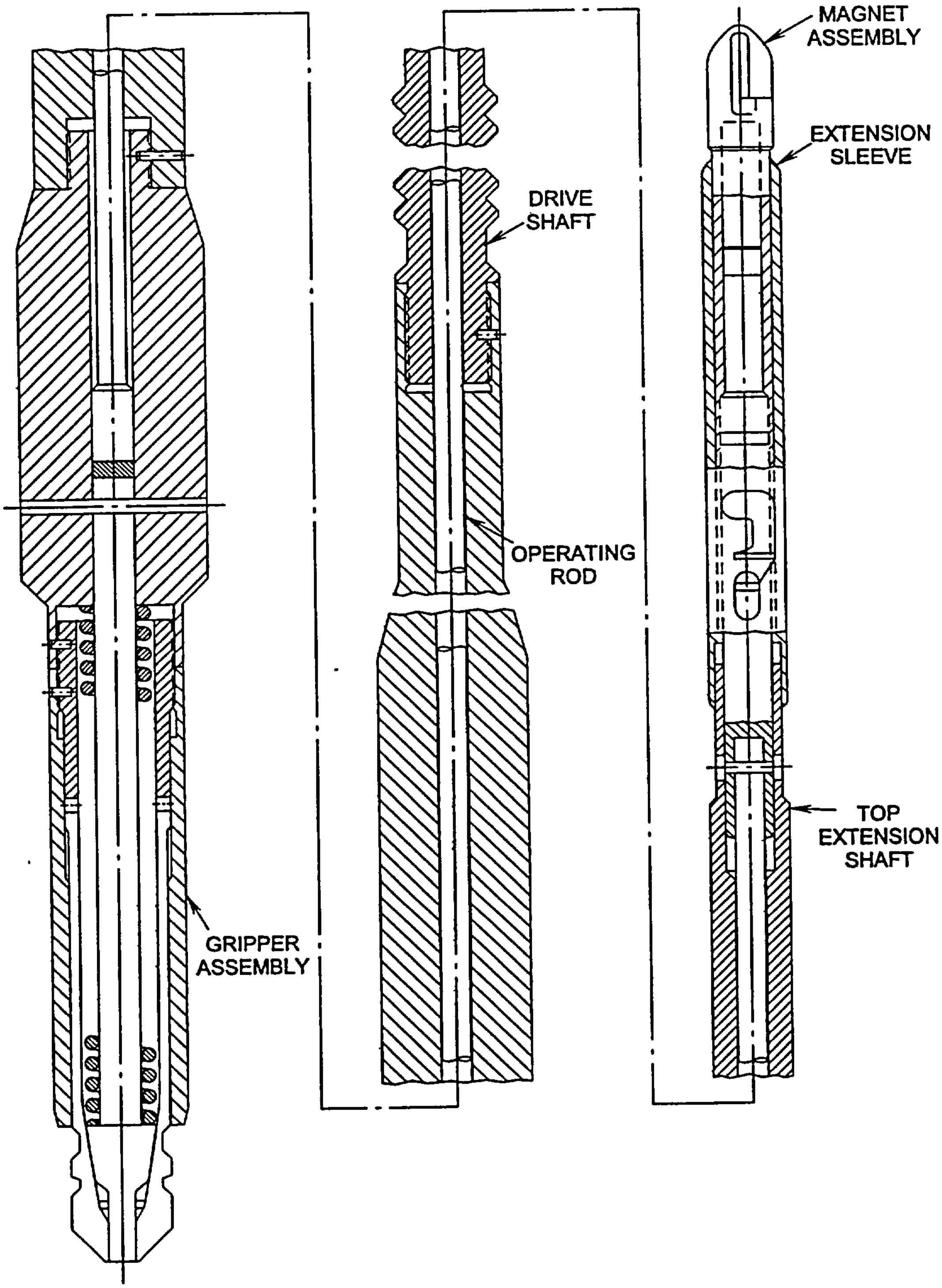
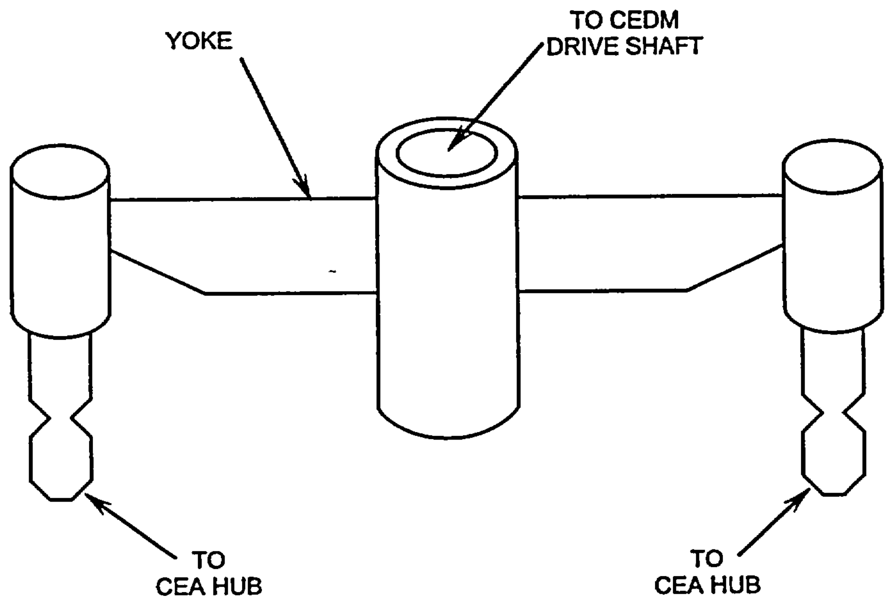
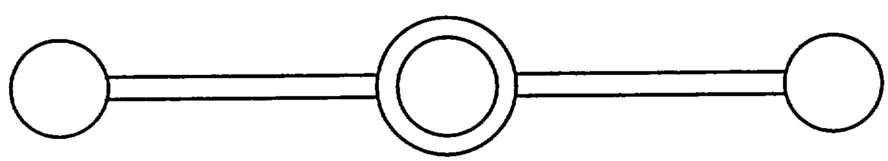


Figure 3-1 CEA Drive Shaft





TOP VIEW

Figure 3-2 Dual CEA Coupling

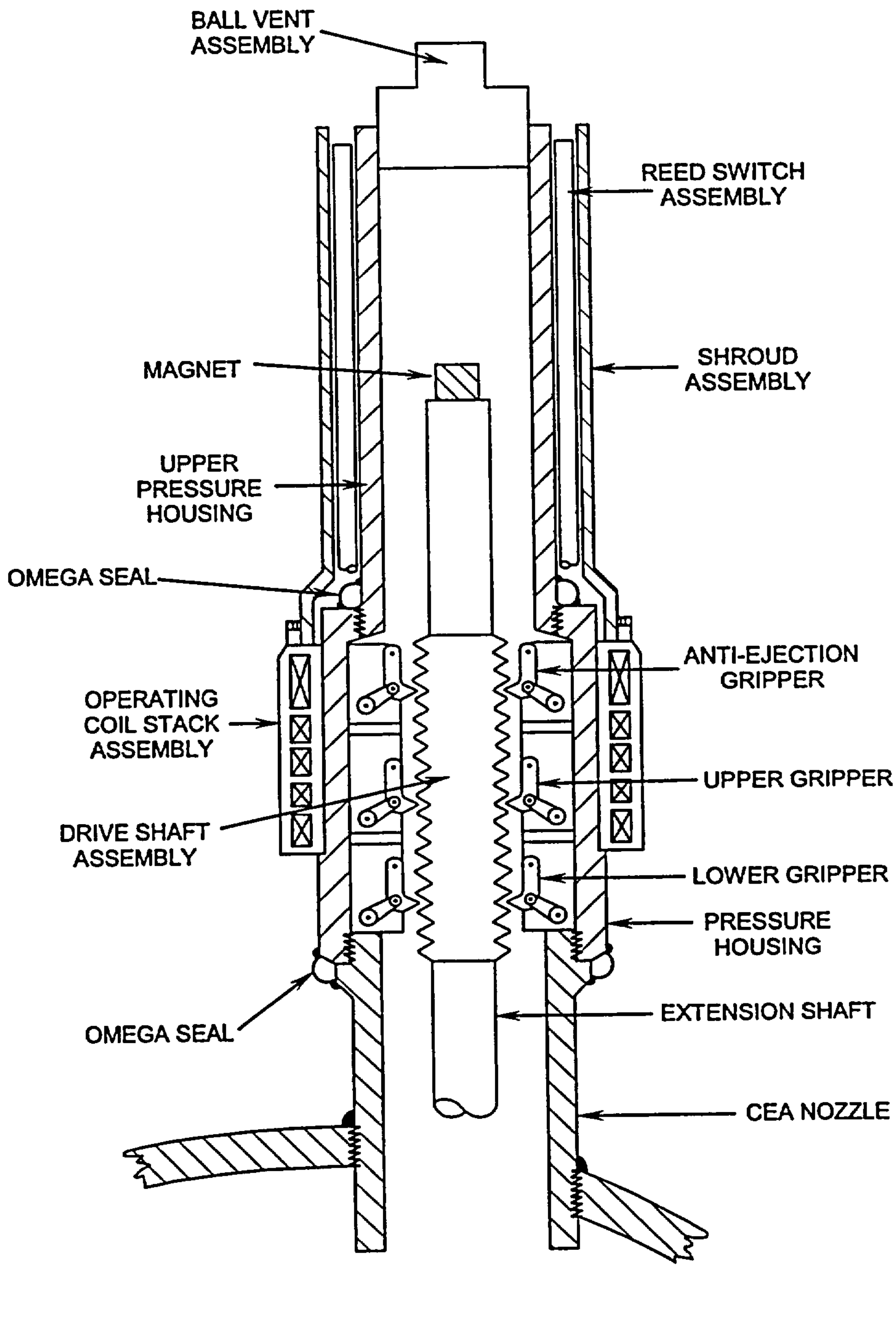


Figure 3-3 Pressure Housing and Drive Unit

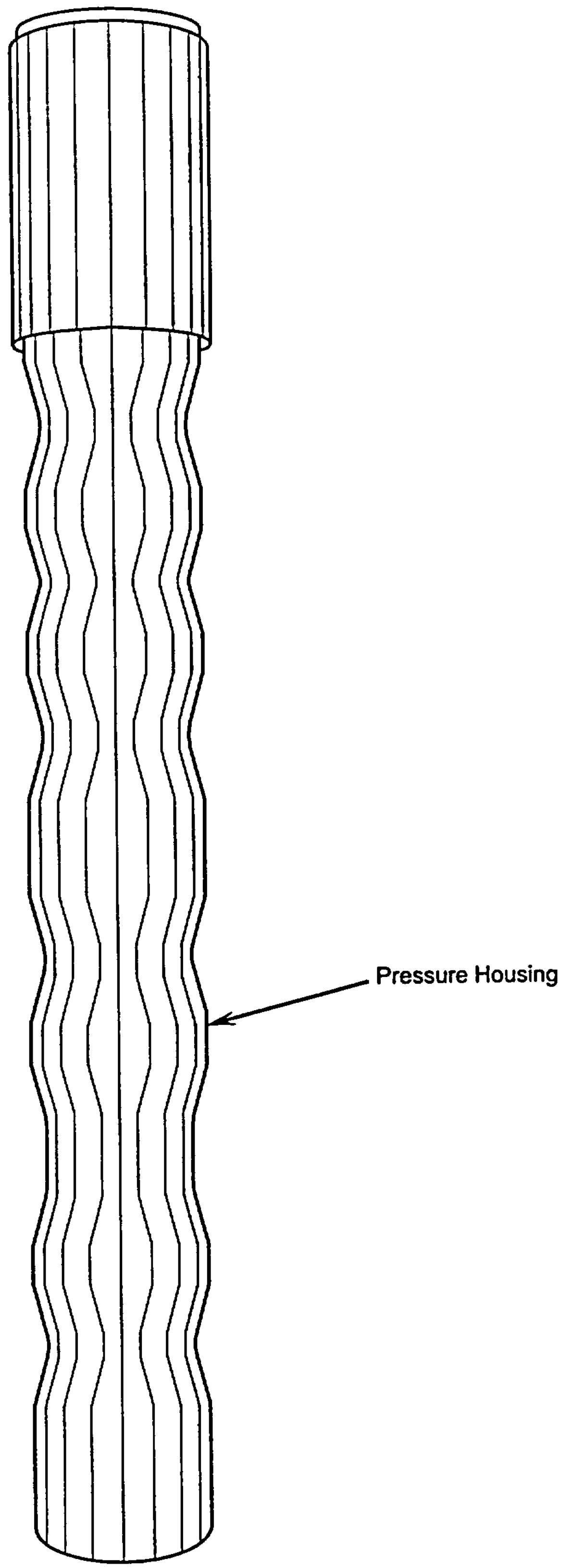


Figure 3-4 CEA Motor Assembly

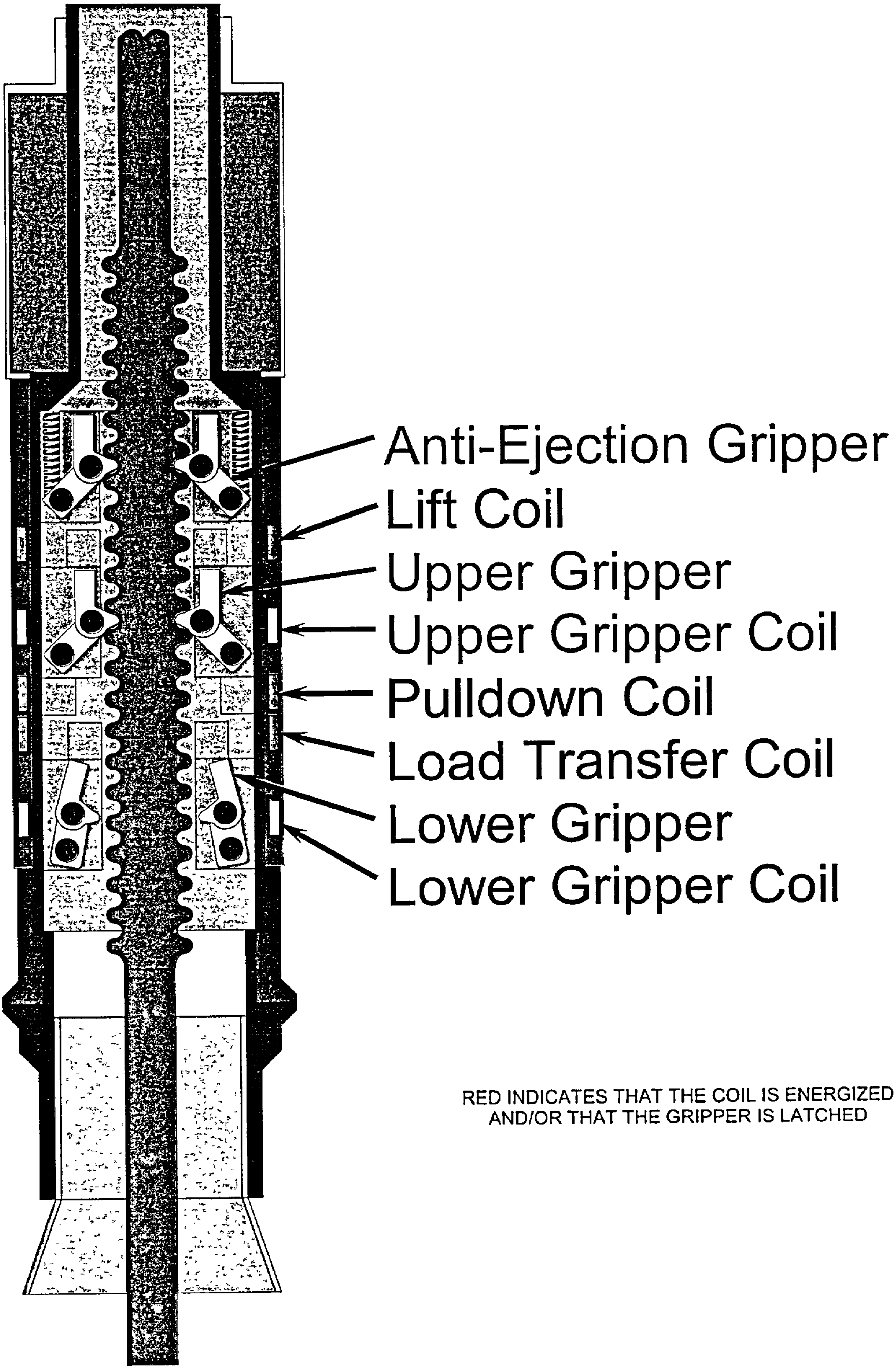
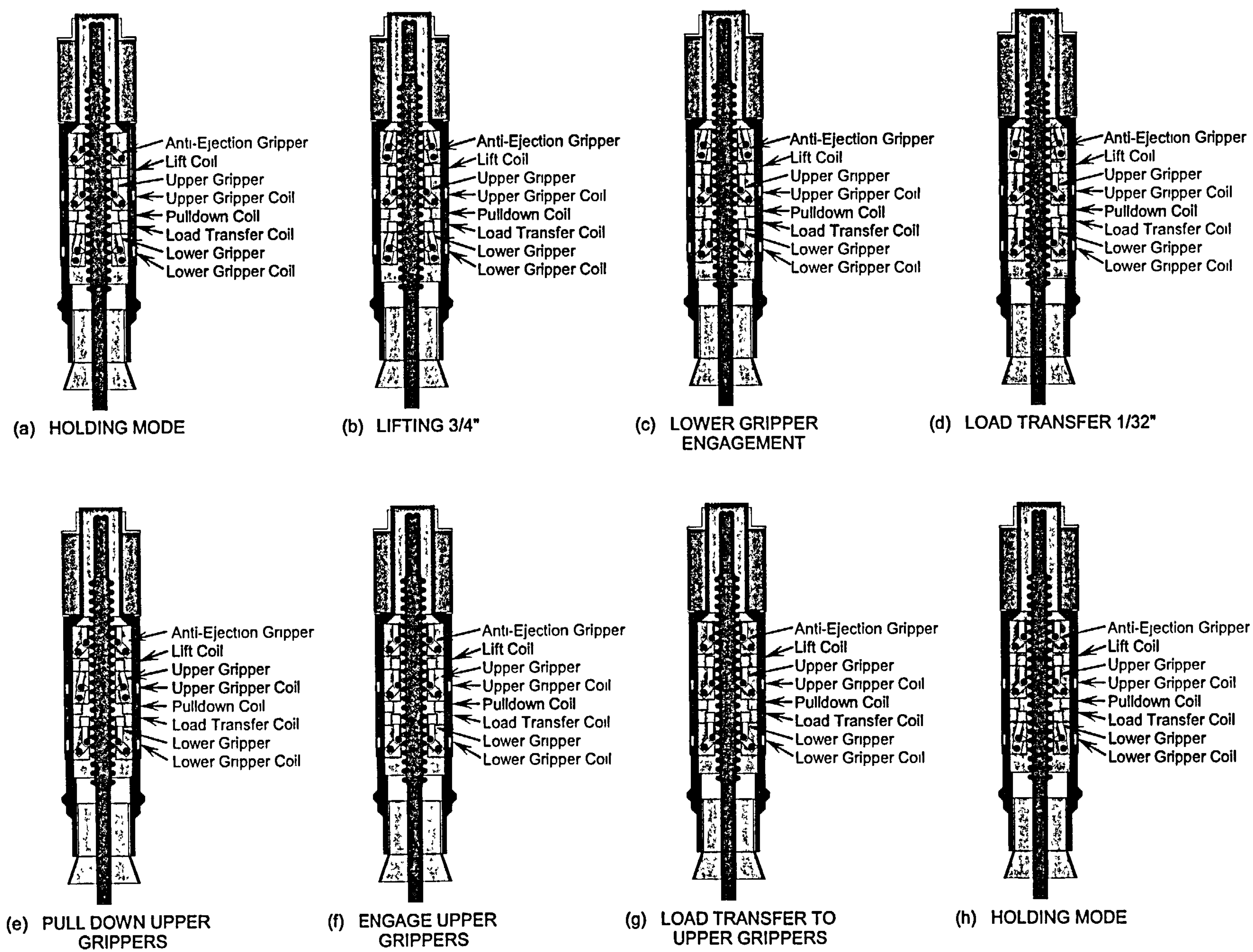


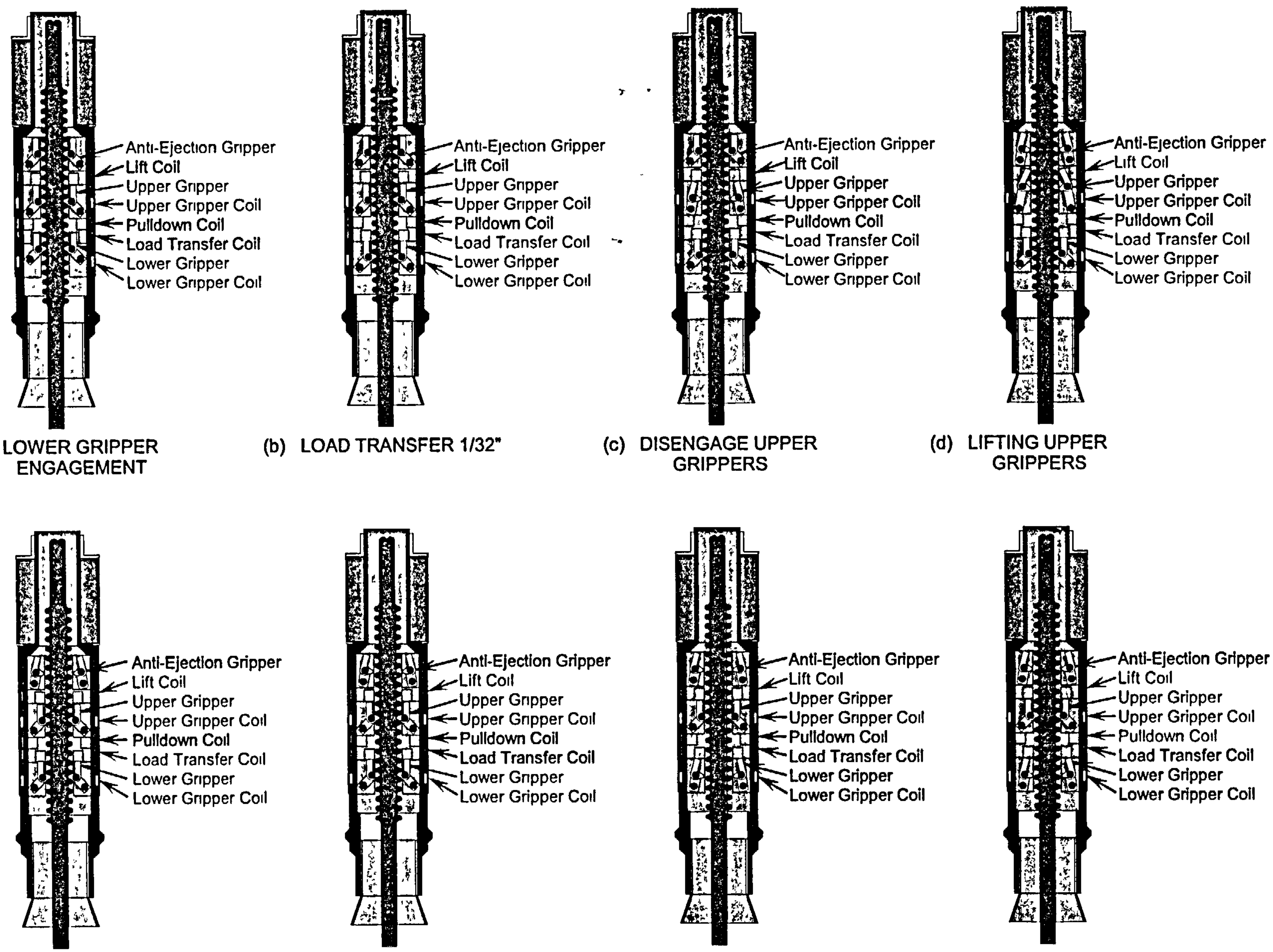
Figure 3-5 Hold Mode



RED INDICATES THAT THE COIL IS ENERGIZED AND/OR THAT THE GRIPPER IS LATCHED

Figure 3-6 CEA Withdrawal Sequence

0702-0



(a) LOWER GRIPPER ENGAGEMENT

(b) LOAD TRANSFER 1/32"

(c) DISENGAGE UPPER GRIPPERS

(d) LIFTING UPPER GRIPPERS

(e) ENGAGE UPPER GRIPPERS

(f) LOAD TRANSFER TO UPPER GRIPPERS

(g) DISENGAGE LOWER GRIPPERS

(h) INSERTING 3/4"

RED INDICATES THAT THE COIL IS ENERGIZED AND/OR THAT THE GRIPPER IS LATCHED

Figure 3-7 CEA Insertion Sequence

1000-03

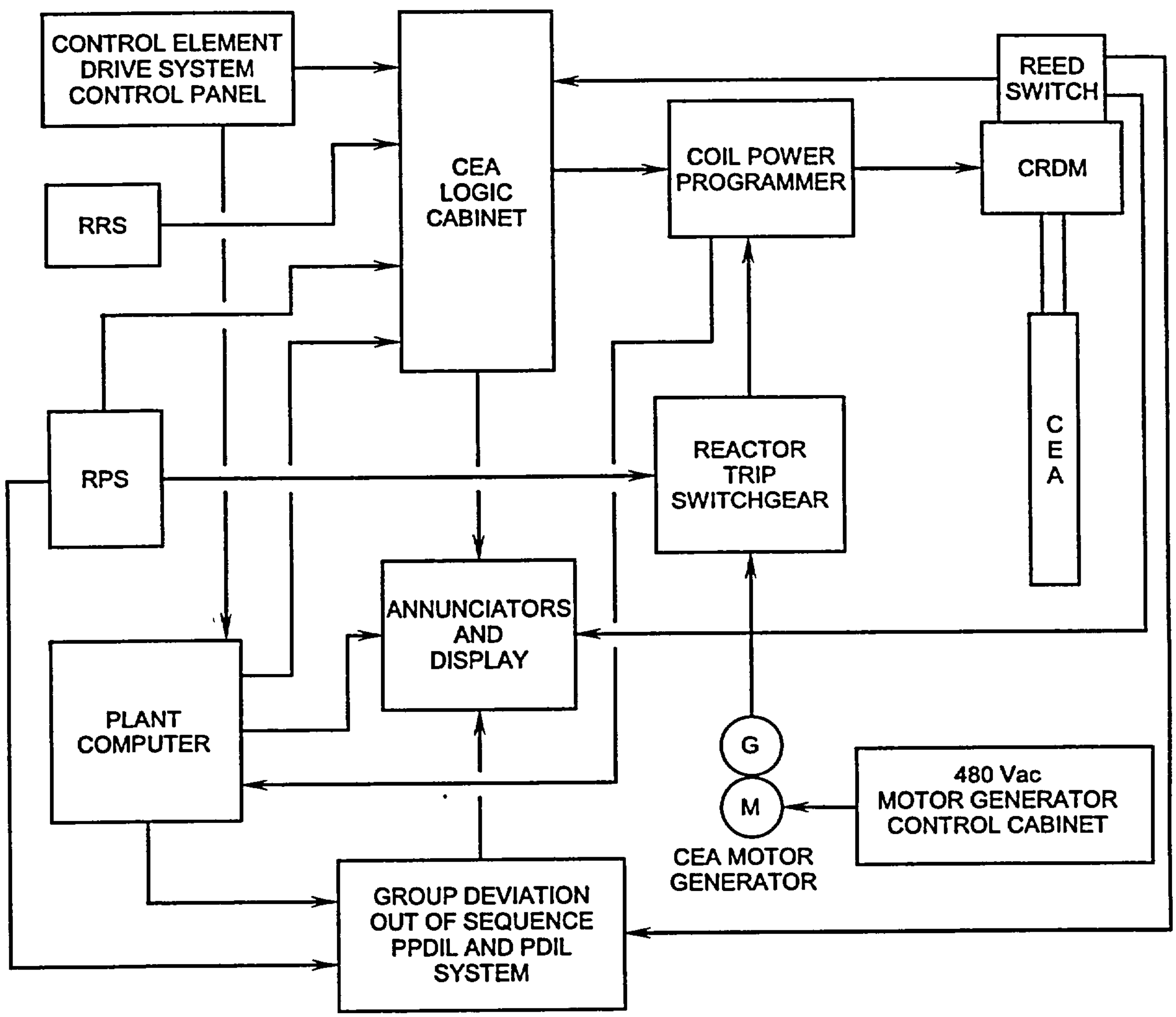


Figure 3-8 CEDS Block Diagram

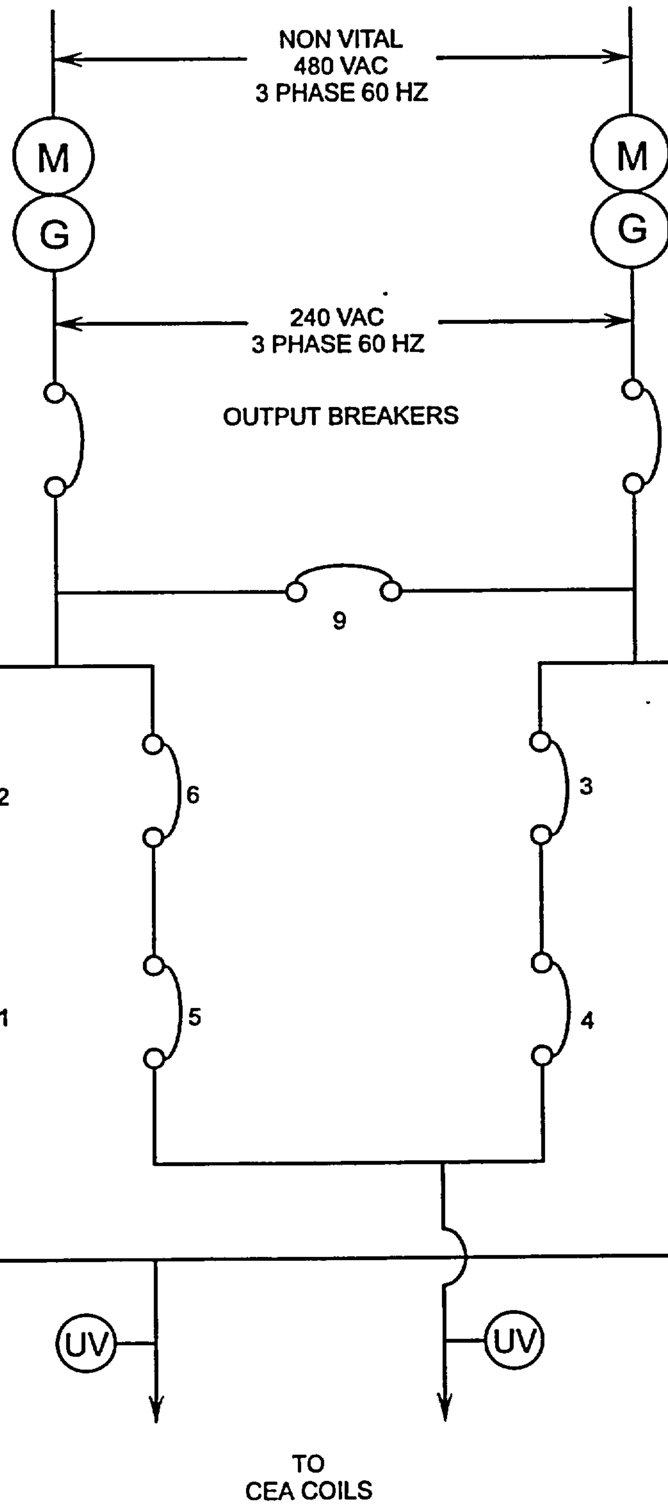


Figure 3-9 CEA Power Supply

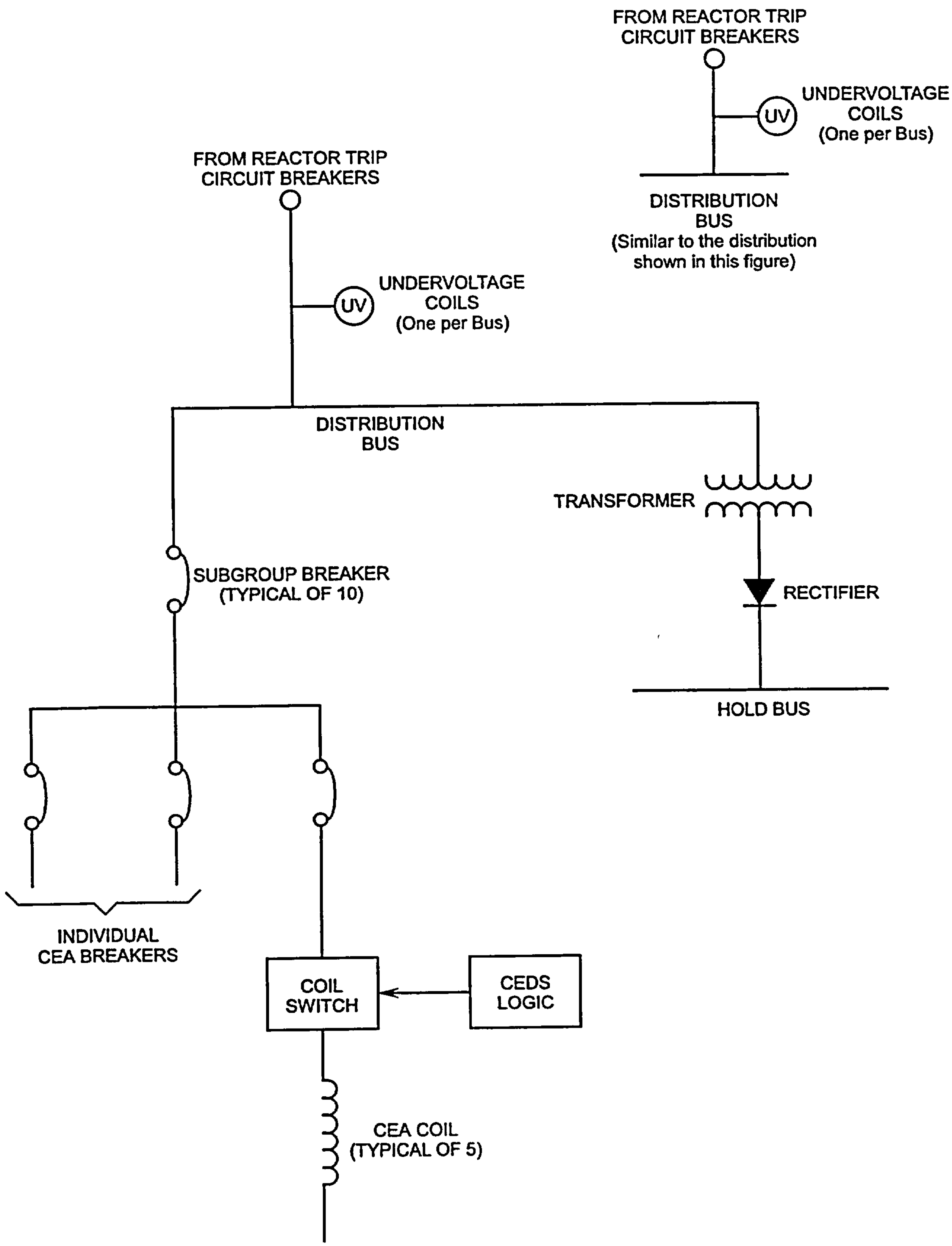


Figure 3-10 CEA Distribution Bus

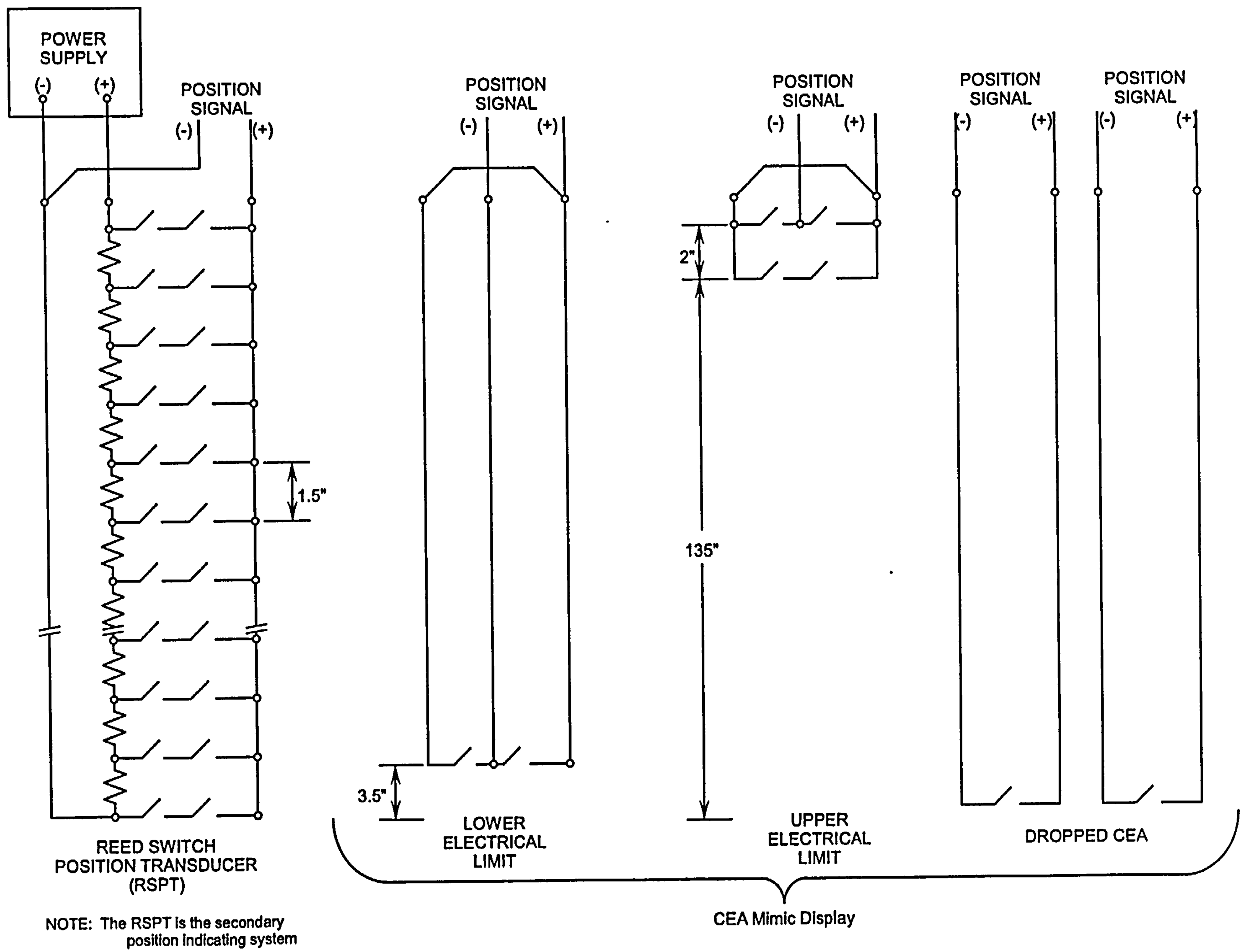


Figure 3-11 Reed Switch Assembly

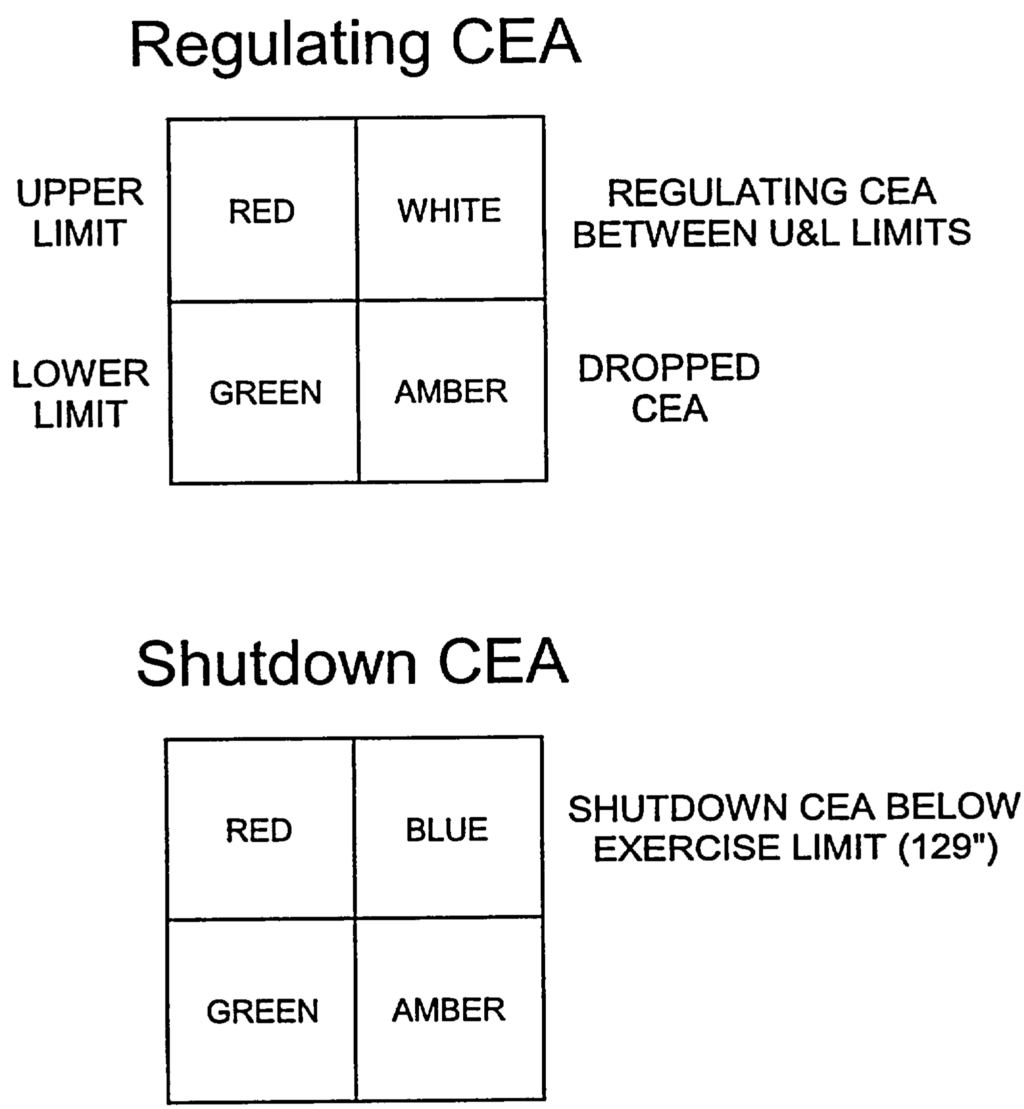


Figure 3-12 CEA Four Lamp Display

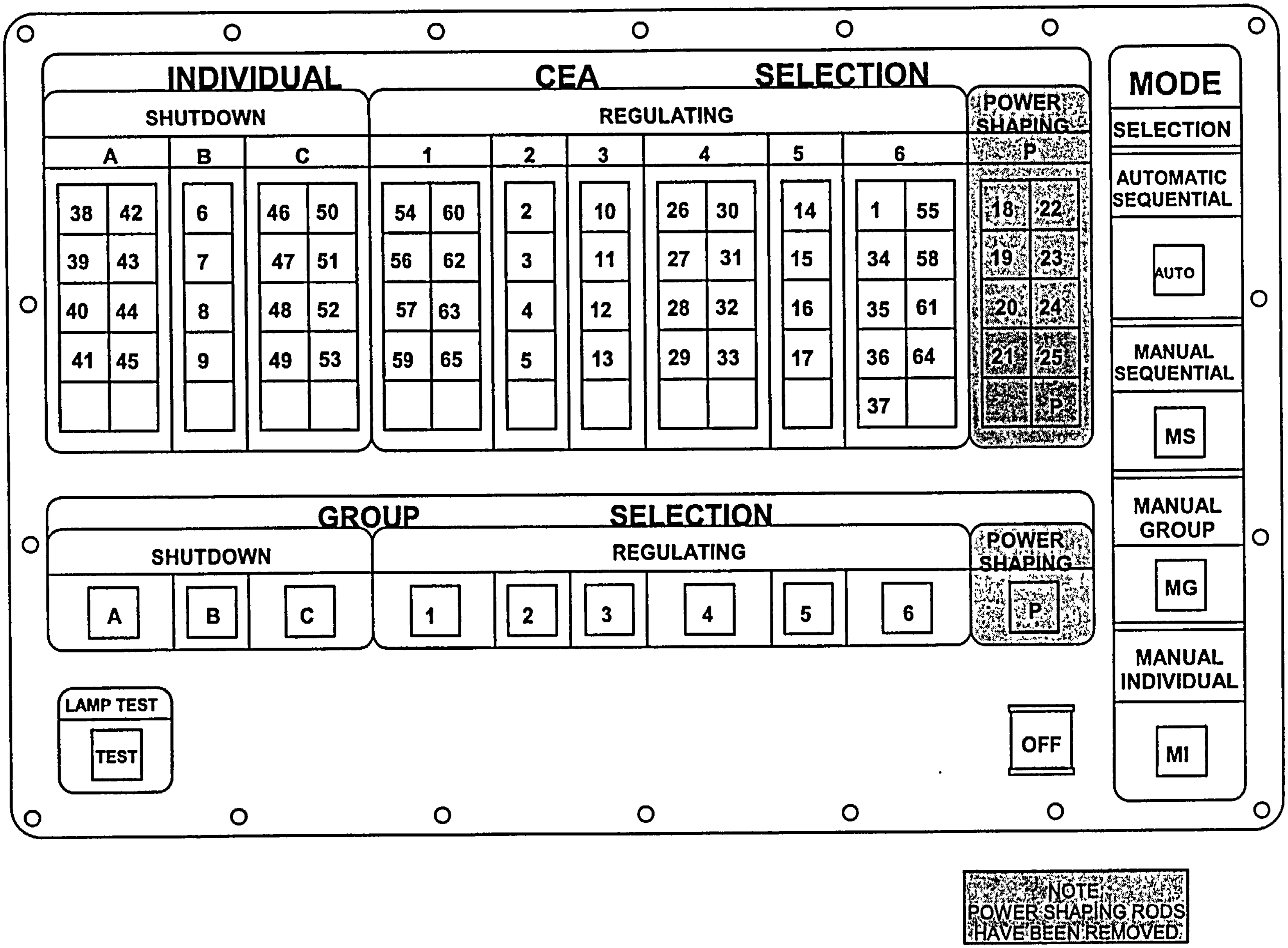


Figure 3-13 CEDS Control Panel

Combustion Engineering Technology
Cross Training Course Manual

Chapter 4

REACTOR REGULATING SYSTEM

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4.0 REACTOR REGULATING SYSTEM

LIST OF FIGURES

4.0 REACTOR REGULATING SYSTEM

Learning Objectives:

1. State the purpose of the reactor regulating system (RRS).
2. List the input signals to the RRS.
3. List the RRS system interfaces.

4.1 Introduction

The RRS performs the following functions:

1. Automatically controls average RCS temperature (Tavg) between 15% and 100% power during:
   a. steady state conditions
   b. 5% ramp changes in load
   c. 10% step changes in load
2. Automatically controls Tavg in conjunction with the steam dump and bypass control system (SDBCS) during the following:
   a. load rejections
   b. turbine trips
   c. turbine setbacks
3. Provides a programmed pressurizer water level setpoint to the pressurizer water level control system (PLCS).

There are two independent RRS systems installed in the plant. Either RRS may be selected to control the control element assembly (CEA) regulating groups and to supply the pressurizer water level setpoint.

To illustrate the need for the RRS, consider the effect on unit operation when a step load increase from 20 to 30% occurs with CEA control in manual. As turbine load is increased, secondary plant heat removal increases while reactor heat generation remains constant. The mismatch between heat removal and generation causes a reduction in RCS Tavg. When Tavg drops, positive reactivity is added to the core and reactor power begins to increase. The increase in reactor power is dampened by the negative reactivity added by the doppler coefficient. As a result, heat removal continues to exceed heat production and Tavg continues to decrease. The above actions will continue until the reactor's heat production is equal to the turbine's heat removal. At the end of the transient, the following conditions will exist:

1. Reactor power will equal turbine power, and
2. Tavg will be lower than its original value.

This reduced Tavg results in a lower steam pressure and therefore, inefficient turbine operation.

A step decrease in load would result in a Tavg value greater than the original temperature. This elevated Tavg represents energy that could be used to generate electrical power. In order to minimize the inherent decrease in steam pressure associated with the U-tube steam generator, a linear ramp of Tavg from 532°F at 0% power to 572.5°F at 100% power is used. The RRS is designed to maintain actual Tavg on the curve by withdrawing or inserting the CEA control groups.

4.2 RRS Inputs

4.2.1 Temperature Inputs

As shown in Figure 4-1, the RRS receives an input of hot (Th) and cold (Tc) leg temperatures from each RCS loop. These outputs are routed to a selector switch that is used to determine the inputs that are used in the calculation of Tavg. The selector switch provides the operator with the option of choosing either loop 1, loop 2, or both loops as inputs to the calculation of Tavg. However, placing the selector switch in the 1 & 2 position will minimize the effect of a temperature detector failure.

The output range of the Tavg calculator is 515°F to 615°F which is the same range as the individual temperature detector inputs. The output of the Tavg calculator is used to generate the pressurizer level setpoint, the steam dump quick open signal, and is also supplied to the temperature summer where it is compared with the reference temperature that is calculated from turbine first stage pressure (Tref).

4.2.2 Turbine First Stage Pressure

Since the purpose of the RRS is to maintain Tavg at the desired value for efficient turbine operation, it is logical to use a turbine load related parameter as an input. Turbine first stage pressure varies linearly as turbine load changes and is used in two different ways by the RRS. First, the first stage pressure input is used to generate the variable Tavg setpoint called reference temperature (Tref). Tref is compared with actual Tavg in the temperature summer and the difference between the temperature values is used to determine rod motion. The second use of turbine first stage pressure is in the development of power error.

As previously stated, first stage pressure is directly proportional to turbine load or power. This turbine power signal is compared with reactor power in the power summer and is used as an anticipatory signal for CEA motion demand.

The output of the power summer is supplied to a rate unit (d/dt). If there is a rate of change of turbine power with respect to reactor power, the rate unit will have an output. For example, if turbine load (power) is decreasing, then the heat production by the reactor exceeds the heat removal by the turbine. The mismatch between turbine and reactor power will cause an increase in RCS Tavg. However, the rate unit senses the decrease in turbine power and supplies a signal to initiate CEA insertion. In this example, CEA motion is initiated before a temperature error is developed in the temperature summer. Of course, the opposite actions would occur if turbine power exceeds reactor power.

4.2.3 Reactor Power Input

The RRS reactor power input is supplied from the control channel associated with each RRS cabinet. The control channel input is used in the development of the power error signal. The non-safety related control channel signal has a range of 0 to 120% power.

4.2.4 Pressurizer Pressure

A pressurizer pressure input (1500-2500 psia) is supplied to the RRS and may be used as an anticipatory signal for CEA motion. Changes in Tavg cause pressurizer level changes which, in turn, change pressurizer pressure. Due to the lag in temperature measurement, the pressurizer pressure signal will reflect temperature changes. A jumper is provided in the RRS to remove this input if it is not required for proper response.

4.3 RRS Circuitry

4.3.1 Temperature Lag Circuit

The output of the temperature summer is supplied to a lead/lag unit that functions to delay the temperature error. The delayed signal allows reactor power to overshoot or undershoot the value of turbine power and create a small power mismatch to increase or decrease the stored energy in the RCS.

4.3.2 Total Error Summer

The total error summer receives inputs from the temperature summer, the power summer, and pressurizer pressure (if used). The output signal is a temperature error signal that has been modified by the rate of change of power and pressurizer pressure. The summer output will be used in determining CEA speed and direction.

4.3.3 CEA Rate Circuit

The modified temperature error signal from the output of the total error summer is used in determining the speed of CEA movement. As shown on Figure 4-2, equivalent temperature errors of 2°F result in low rate CEA motion while errors of 3°F result in high rate CEA motion. Low rates of CEA insertion or withdrawal occur at three (3) inches per minute. High rates of CEA insertion or withdrawal occur at 30 inches per minute.

4.3.4 CEA Direction Circuit

The output of the total error summer is also supplied to the CEA direction circuit which is used to determine the need for CEA insertion or withdrawal. When the temperature error is less than ± 2°F, no CEA motion will occur in either direction. This 2°F deadband prevents unnecessary CEA motion. When the error exceeds +2°F (Tavg > Tref) inward CEA motion will occur at the rate determined by the CEA rate circuit. When the temperature error exceeds - 2°F (Tavg < Tref), CEA withdrawal will occur at the rate determined by the CEA rate circuit. These values and directions are shown on Figure 4-2.

4.4 RRS Operations

4.4.1 Plant Startup

After the plant has been heated up to no load Tavg (532°F) by RCP energy, criticality is achieved by manual CEA withdrawal. Manual control of the CEAs is maintained until reactor power is equal to 15%. During this period, the RRS is supplying the pressurizer level control system with the programmed level setpoint. At 15%, the control element drive system (CEDS) may be placed in the automatic sequential mode and the RRS can be used to maintain Tavg during the remainder of the power escalation. However, technical specifications dictate that the last CEA group be maintained at least 90 inches withdrawn when power is greater than 20%. This leaves only a very small amount of available positive reactivity that can be added to overcome the power coefficient's negative reactivity. Therefore, the escalation in power must be accomplished by a combination of CEA withdrawal and boron dilution. Once the unit is at 100% power, the RRS can be used for load reductions or ramp changes induced by equipment problems or grid disturbances.

4.4.2 Ramp Load Reduction

Figure 4-3 illustrates the control actions performed by the RRS when turbine load is reduced from 100% to 15% at 5% per minute. The reduction in turbine load causes a decrease in the turbine first stage pressure input. The decreased turbine first stage pressure input has two effects:

1. An output from the power error (d/dt) rate circuit, and

2. An output from the temperature summer because Tref drops below Tavg.

These two outputs combine to cause CEA insertion. The reduction of turbine power is faster than the decrease in reactor power. This provides the necessary power mismatch required for a decrease in Tavg. At about 1100 seconds, reactor power decreases below turbine power and Tavg decreases below Tref. This reverses the direction of CEA motion. Other corrective oscillations occur to fine tune Tavg to within the control band.

4.4.3 Step Load Decrease

As shown on figure 4-4, the step load reduction causes CEA insertion at the high rate. This initial rate is caused by the output of the power error circuit as it senses a very large rate of change. CEA insertion continues at a high rate (primarily due to the large temperature error) until reactor power drops below turbine power. This condition causes a reversal in the output of the derivative unit and drops the insertion rate to low speed because power error is now subtracted from the temperature error circuit. With reactor power below turbine power, Tavg begins to drop. The remainder of the transient is more dependent upon reactivity effects than RRS actions.

4.5 RRS Indications

The following is a listing of RRS indications that are available for use by the control room operator:

1. Tavg/Tref recorder - One (1) two (2) pen recorder per RRS. One pen indicates Tavg, while the second pen registers the value of Tref.

2. Tavg indication indicates the value of Tavg from the selected RRS.

3. CEA status lamps (5) provide the following indication:
   a. High rate CEA withdrawal,
   b. Low rate CEA withdrawal,
   c. Hold,
   d. High rate CEA insertion and
   e. Low rate CEA insertion.

4. A level setpoint provides indication of the calculated pressurizer level setpoint.

4.6 RRS Interfaces

In addition to supplying the pressurizer level control system with its setpoint, the RRS also interfaces with the CEDS and SDBCS. The CEDS interface consists of CEA rate, CEA direction, and automatic withdrawal prohibit (AWP) signals. AWP signals prevent CEA withdrawal if a high Tc or a large Tavg/Tref error exists. The interfaces with the SDBCS consist of the Tavg input which is used in the quick opening logic.

4.7 Summary

The RRS is installed to maintain the desired ramp of Tavg as power is increased. The ramp in Tavg minimizes the reduction in steam pressure which, in turn, improves turbine efficiency. The RRS receives inputs from Tavg, turbine first stage pressure, and linear control channel reactor power. In addition to controlling Tavg, the RRS also supplies the pressurizer level control system and the steam dump and bypass control system.

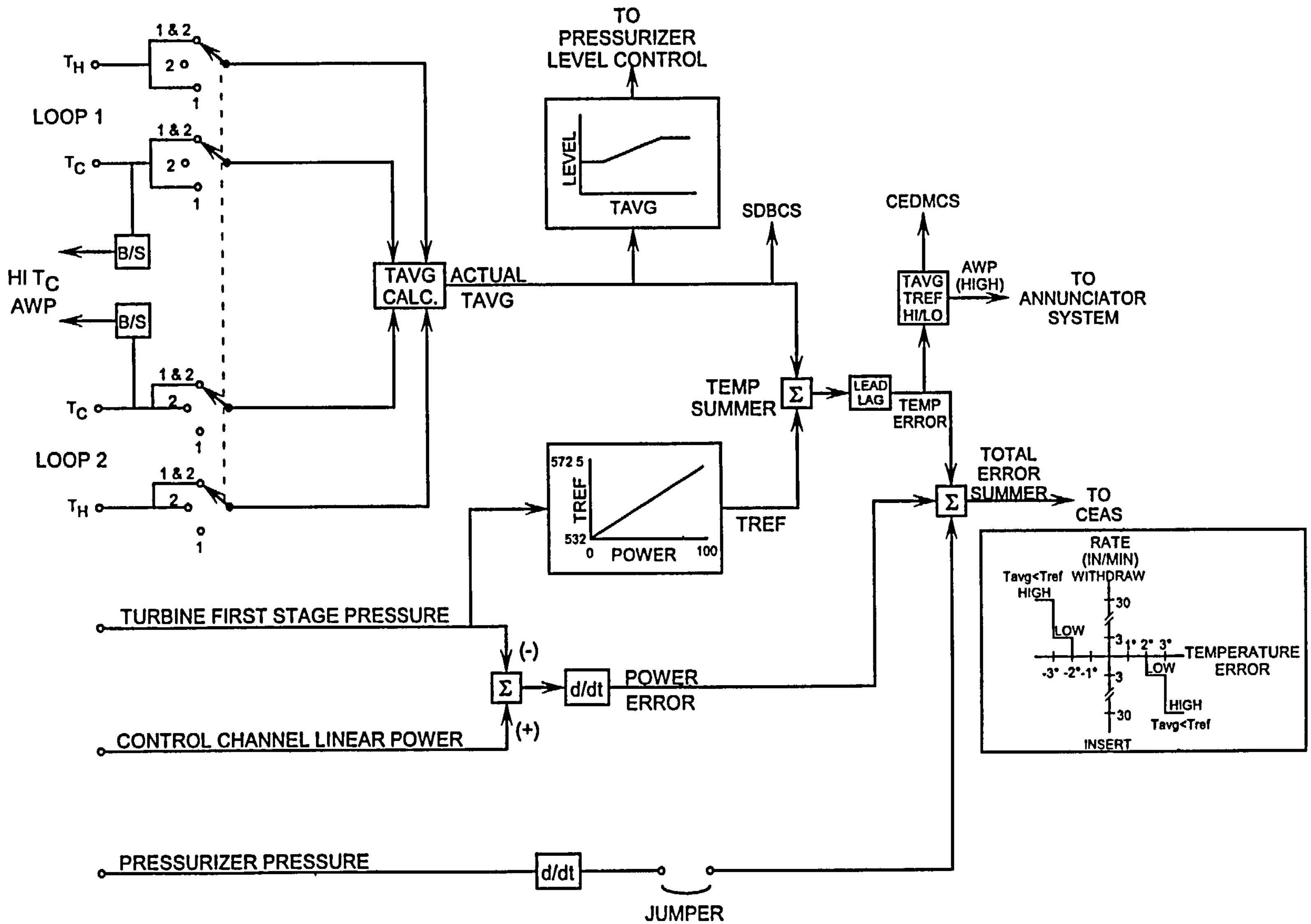

Figure 4-1 Reactor Regulating System

1201-04

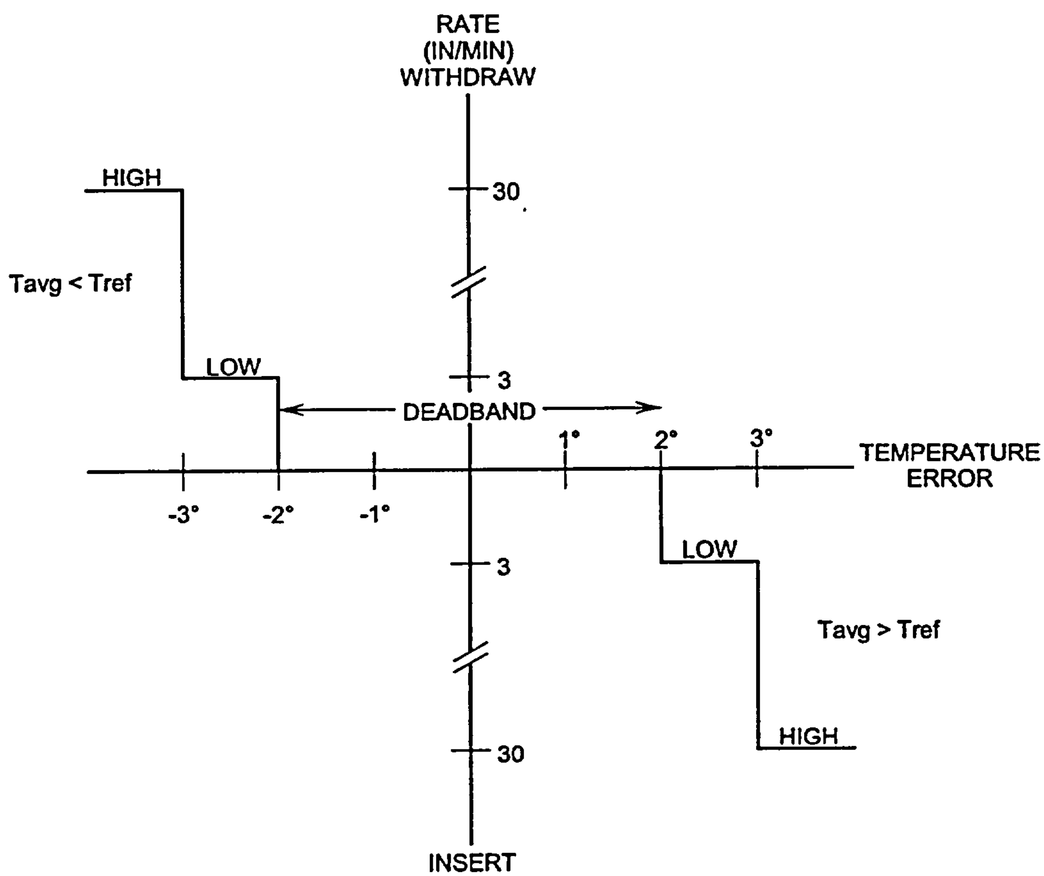

Figure 4-2 CEA Rates and Direction

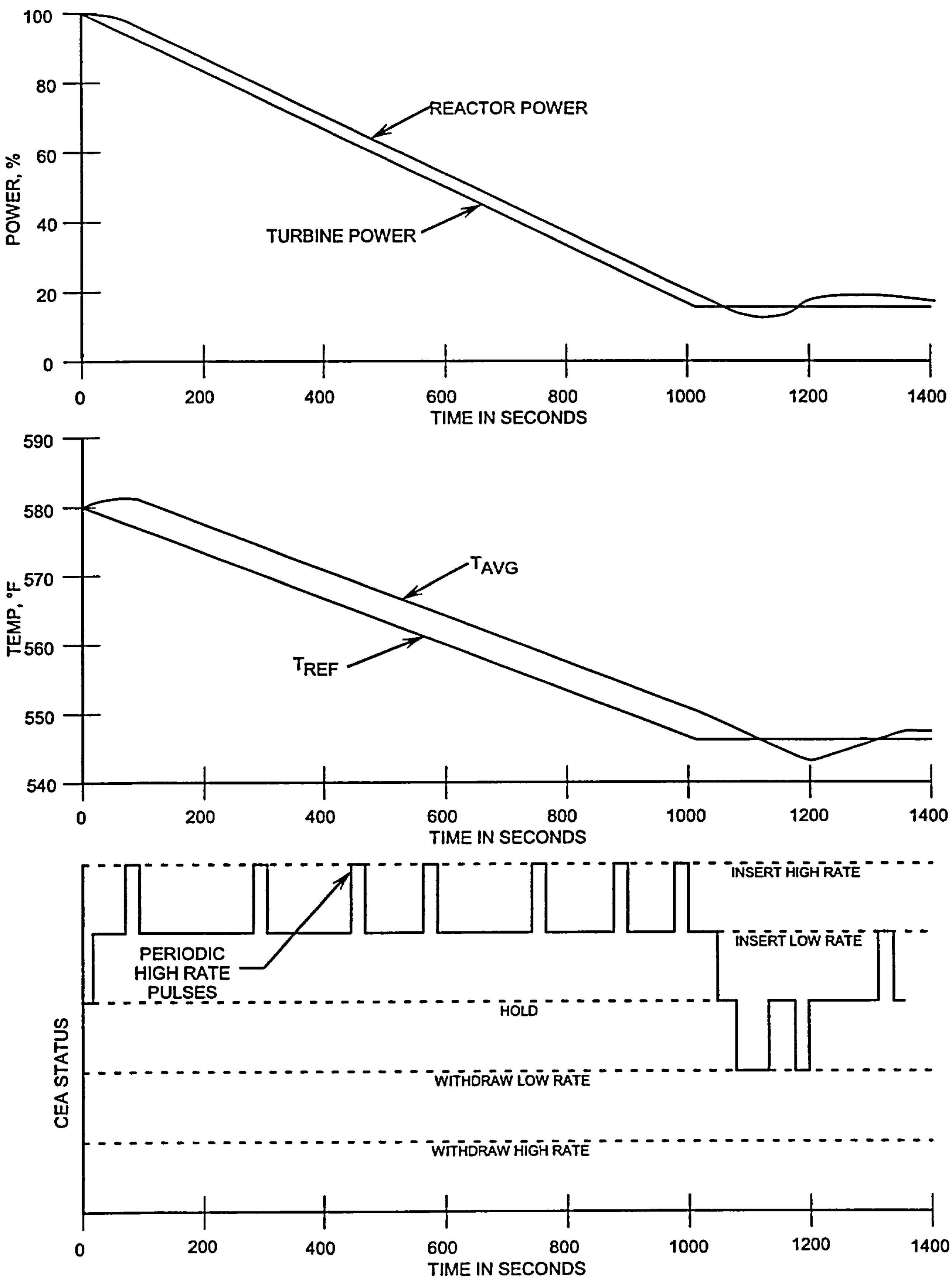

Figure 4-3 Ramp Load Reduction

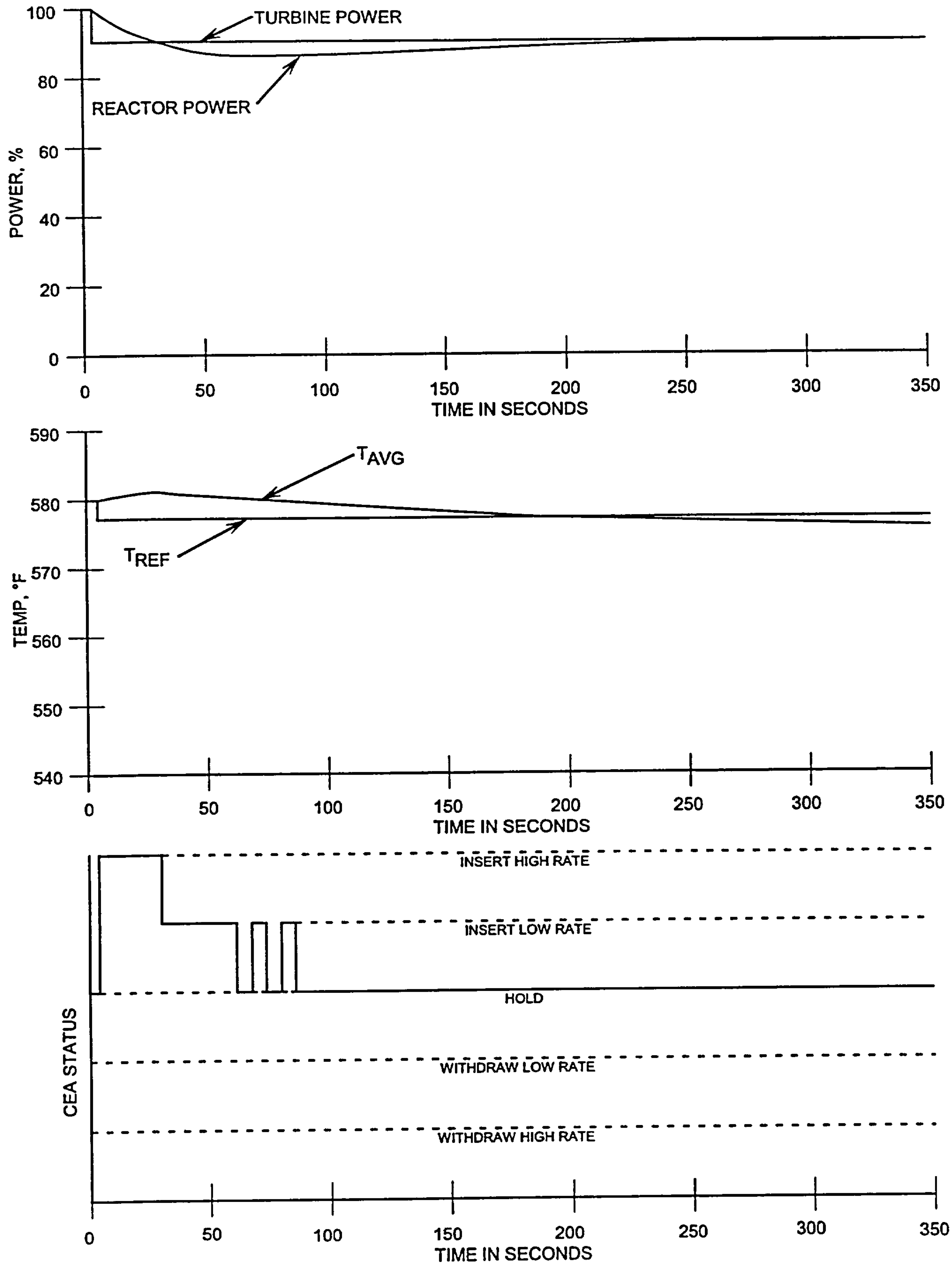

Figure 4-4 Step Load Reduction